Q1/13

ENERPLUS FIRST QUARTER REPORT
THREE MONTHS ENDED MARCH 31, 2013

ENERPLUS

SELECTED FINANCIAL RESULTS	Three months ended March 31, 2013	2012
Financial (000's)		
Funds Flow	$ 172,596	$ 162,706
Cash and Stock Dividends	53,785	105,995
Net Income/(Loss)	(5,238)	(33,821)
Debt Outstanding – net of cash	1,125,762	902,937
Capital Spending	172,944	317,066
Property and Land Acquisitions	3,967	33,020
Property Dispositions	1,331	52,611
Asset Disposition Gain	217	24,100
Debt to Trailing 12 Month Funds Flow	1.7x	1.6x
Financial per Weighted Average Shares Outstanding		
Funds Flow	$ 0.87	$ 0.86
Net Income/(Loss)	(0.03)	(0.18)
Weighted Average Number of Shares Outstanding (000's)	199,031	189,844
Selected Financial Results per BOE(1)		
Oil & Gas Sales(2)	$ 46.67	$ 47.04
Royalties	(9.52)	(9.26)
Commodity Derivative Instruments	1.47	(1.48)
Operating Costs	(10.42)	(9.81)
General and Administrative Expenses	(3.15)	(2.87)
Equity Based Compensation	(0.70)	(0.22)
Interest and Other Expenses	(2.19)	(0.72)
Taxes	(0.16)	(0.10)
Funds Flow	**$ 22.00**	**$ 22.58**

SELECTED OPERATING RESULTS	Three months ended March 31, 2013	2012
Average Daily Production		
Crude oil (bbls/day)	38,321	34,074
NGLs (bbls/day)	3,595	4,002
Natural gas (Mcf/day)	271,602	246,686
Total (BOE/day)	87,183	79,190
% Crude Oil & NGLs	48%	48%
Average Selling Price(2)		
Crude oil (per bbl)	$ 78.52	$ 85.91
NGLs (per bbl)	58.58	56.77
Natural gas (per Mcf)	3.10	2.27
Net Wells drilled	25	34

(1) Non-cash amounts have been excluded.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

	Three months ended March 31, 2013	2012
Average Benchmark Pricing		
WTI crude oil (US$/bbl)	$ 94.37	$ 102.93
AECO natural gas – monthly index (CDN$/Mcf)	3.08	2.52
AECO natural gas – daily index (CDN$/Mcf)	3.20	2.15
NYMEX natural gas – monthly NX3 index (US$/Mcf)	3.35	2.77
USD/CDN exchange rate	1.01	1.00

Share Trading Summary **For the three months ended March 31, 2013**	**CDN* – ERF** (CDN$)	**U.S.** – ERF** (US$)
High	$ 15.50	$ 15.17
Low	$ 12.26	$ 12.03
Close	$ 14.84	$ 14.61

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

2013 Dividends per Share **Payment Month**	**CDN$**	**US$(1)**
January	$ 0.09	$ 0.09
February	$ 0.09	$ 0.09
March	$ 0.09	$ 0.09
First Quarter Total	**$ 0.27**	**$ 0.27**

(1) 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 strong results for the first quarter of 2013 have positioned us well to achieve all of our operational targets this year. Our portfolio of core assets in Canada and the U.S. continued to deliver profitable, organic growth. With strong base performance across our portfolio and the successful execution of our capital plans we achieved average production of 87,183 BOE per day during the quarter. This growth was in part driven by record production levels from our assets at Fort Berthold, North Dakota and the Marcellus region in Pennsylvania. Most notably, our Marcellus production increased significantly, averaging 79 MMcf per day, up from 57 MMcf/day during the fourth quarter as a result of strong well performance and increased tie-in activity late in 2012.

We closely managed our capital spending program as part of our strategy to improve the sustainability and profitability of our business. We invested $173 million during the quarter, approximately 25% of our capital spending guidance for the year. The majority of our spending was once again directed to our crude oil projects in Canada and the U.S. Approximately 45% of our spending was directed to our Bakken development at Fort Berthold, North Dakota where we realized a reduction in well costs during the quarter. A total of 25 net wells were drilled with 17 net wells brought on stream.

With the steady recovery of natural gas prices and support from our hedging program, we generated $173 million ($0.87 per share) in funds flow during the quarter. Approximately 40% of our total production is now attributable to our U.S. assets which has helped mitigate the impact of widening Canadian heavy crude oil differentials. Our operating costs of $10.37/BOE were in line with our guidance, and while our general and administrative costs were higher than expected due to one-time charges, we continue to maintain our annual guidance for both these items.

Our adjusted payout ratio was approximately 126%, a significant improvement from 254% a year ago due to the increase in funds flow and reductions in our capital spending and monthly dividend. We have continued to keep our balance sheet strong with a debt to trailing 12 month funds flow ratio of 1.7 times at the end of the quarter. Approximately 70% of our $1 billion credit facility remains unutilized. We are also well positioned with hedges on approximately 65% of our net crude oil production and 35% of our net natural gas production for 2013 that we expect will provide us with significant funds flow protection in 2013. This will help ensure we have the financial capacity to support our capital spending plans and our dividend.

Subsequent to the quarter, we sold approximately 600 BOE per day of low working interest crude oil production in southeast Saskatchewan and Alberta for $58 million. These assets were not considered part of our core portfolio and their sale not only increases our financial flexibility, but it also improves the focus and concentration of our asset base. We are also currently marketing a package of small non-core properties representing approximately 1,300 BOE per day of primarily oil production in order to further focus our portfolio.

We are maintaining our annual average production guidance of 82,000 to 85,000 BOE per day with an exit rate of 84,000 to 88,000 BOE per day, despite the sale of 600 BOE/day. Our guidance does not reflect the potential divestment activities detailed above as we cannot predict the outcome of these efforts.

Production and Capital Spending

	Three months ended March 31, 2013	
	Average Production Volumes	**Capital Spending** ($ millions)
Crude Oil & NGLs (BOE/day)		
Canada	22,284	$ 47
United States	19,632	77
Total Crude Oil & NGLs (BOE/day)	41,916	$ 124
Natural Gas (Mcf/day)		
Canada	177,809	$ 36
United States	93,793	13
Total Natural Gas (Mcf/day)	271,602	$ 49
Company Total (BOE/day)	87,183	$ 173

Net Drilling Activity – for the three months ended March 31, 2013

	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Crude Oil						
Canada	14.4	0.4	14.8	10.9	4.2	–
United States	3.7	–	3.7	2.8	7.7	–
Total Crude Oil	**18.1**	**0.4**	**18.5**	**13.7**	**11.9**	**–**
Natural Gas						
Canada	5.4	–	5.4	2.4	3.2	–
United States	0.8	–	0.8	0.8	1.7	–
Total Natural Gas	**6.2**	**–**	**6.2**	**3.2**	**4.9**	**–**
Company Total	**24.3**	**0.4**	**24.7**	**16.9**	**16.8**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment as at March 31, 2013.
** Total wells brought on-stream during the quarter regardless of when they were drilled.

U.S. Crude Oil

Our U.S. crude oil production increased by approximately 7% during the first quarter of 2013 compared to the fourth quarter of 2012 due to the additional working interests purchased in the Sleeping Giant field in Montana in December 2012 and continued drilling at Fort Berthold in North Dakota. We invested $77 million during the quarter in North Dakota targeting both the Bakken and Three Forks formations. We drilled three net operated long horizontal wells and participated in one non-operated well. In addition, five operated long horizontal wells, two short horizontal wells and one non-operated well were brought on stream.

The Fort Berthold region continues to be our most active development area within our portfolio. Our focus in 2013 is on improving our capital efficiencies and to continue to deliver growth in production and reserves. We initially budgeted $12.9 million for the drilling, completion and tie-in of a long horizontal well in 2013. During the quarter we realized savings in the order of 10% due primarily to lower costs for completion services and supplies. We are encouraged by these cost reductions and will work to extend them throughout the remainder of the year. In total, we plan to drill, complete and tie-in approximately 20 to 25 wells in 2013.

U.S. Natural Gas

Our U.S. natural gas production continued to grow during the first quarter. Marcellus production increased from approximately 57 MMcf per day during the fourth quarter of 2012 to average 79 MMcf per day during the first quarter, well ahead of our expectations. While drilling activity slowed down as expected, we continue to benefit from better than expected well performance and increased tie-in activity late in 2012. Our Marcellus capital program this year is almost exclusively focused on the northeast region of Pennsylvania. With the recent strengthening in NYMEX natural gas prices, the economics of our capital program have improved significantly. Our Marcellus production is currently delivering a netback of approximately $2.50 per Mcf.

Canada Crude Oil

Capital spending activities to date in our Canadian crude oil portfolio were focused primarily at our Medicine Hat Glauconitic "C" property in Alberta and in Saskatchewan where we continued to drill into the Ratcliffe trend.

At Medicine Hat, we continued with our waterflood optimization program drilling five injection and two producing wells into the field during the quarter. We also began work on a significant battery upgrade to support the growing production from this field. In addition to our waterflood program, we continue to be encouraged by the response to our polymer injection project which began in mid-2012. We expect to make a decision on a second polymer project in this field by year end.

In Saskatchewan, we drilled three horizontal wells targeting the Ratcliffe at our Freda Lake and Neptune properties during the quarter. We expect to complete and tie-in these wells during the second quarter. We have been very pleased with our drilling results in this area as we've grown production from approximately 700 BOE/day in 2010 to over 3,500 BOE/day during the quarter. After spring break-up, we expect to run one rig over the balance of the year and plan to continue to convert older vertical producing wells into water injection wells to optimize the waterfloods in this trend.

Canada Natural Gas

As planned, we have not invested significant capital in our Canadian natural gas assets in 2013 and as a result, daily production has continued to decline. We did however drill two horizontal wells targeting the Wilrich based upon the success of our 2012 drilling program in the Ansell area of Alberta. The first well is meeting our type curve assumptions with a 30-day initial production rate of approximately 6 MMcf per day of natural gas. The second well had an initial peak test rate of approximately 35 MMcf per day during the first 17 hours at 15.3 MPa. The well has been on production since mid-April and production has averaged approximately 17 MMcf per day of natural gas since that time, well ahead of our expectations.

Going Forward

As announced in March, I will be retiring from my role as President and Chief Executive Officer of Enerplus at the end of June. At that time, Ian Dundas, our Executive Vice President and Chief Operating Officer, will succeed me in the role.

Over the course of my tenure at Enerplus we have experienced many challenges and many successes. During the past few years we embarked on a strategy to transition our asset base to improve our profitability and sustainability while maintaining financial strength. We are well along this strategic path as further evidenced by our results in this quarter. I have the utmost confidence in Ian, the rest of the executive team and our staff to continue to build value for our shareholders for years to come.

I wish to thank my fellow executives, board members, Enerplus staff and you, our shareholders, for your support over the years.

Gordon J. Kerr
President & Chief Executive Officer

Management's Discussion and Analysis

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

The following discussion and analysis of financial results is dated May 9, 2013 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus as at and for the three months ended March 31, 2013 and 2012 (the "Interim Financial Statements"),
- the audited consolidated financial statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company") as at and for the years ended December 31, 2012 and 2011; and
- our MD&A for the year ended December 31, 2012 (the "Annual MD&A").

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Interim 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 ("NGL") 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 ("NI 51-101") 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 discussion at 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:

"Adjusted payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate our adjusted payout ratio as dividends to shareholders, net of our stock dividends and the Company's former Dividend Reinvestment Plan ("DRIP") proceeds, 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

Production for the first quarter was up 10% year over year and ahead of expectations at 87,183 BOE/day, primarily due to increased natural gas production from our non-operated Marcellus assets. Capital spending totaled $172.9 million with approximately half of this spending focused on our Fort Berthold crude oil property. Operating expenses were on target for the quarter while general and administrative expenses ("G&A") were in-line with expectations outside of one-time charges.

Funds flow for the quarter increased by 6% to $172.6 million from $162.7 million in the same period in 2012. We continued to see volatility in commodity prices and differentials as our realized natural gas price increased by 37% to $3.10/Mcf while our realized crude oil price decreased by 9% to $78.52/bbl compared to the first quarter of 2012. Our commodity risk management program helped to partially offset lower crude oil prices during the quarter with realized cash gains of $11.6 million.

We reported a net loss of $5.2 million for the quarter as non-cash mark to market losses on our commodity derivatives, resulting from higher forecast commodity prices at quarter end, negatively impacted earnings.

We continue to actively manage our balance sheet to preserve our financial flexibility. Our adjusted payout ratio decreased to 126% in the first quarter of 2013 from 254% in the same period in 2012 mainly due to the decrease in our capital program and reduction in our monthly dividend. At March 31, 2013 we had a trailing twelve month debt to funds flow ratio of 1.7x and $685.7 million of available capacity on our bank credit facility.

While our production during the quarter was ahead of expectations, it is early in the year and we are continuing to maintain all of our previous guidance targets for 2013.

Production

Production in the first quarter of 2013 increased to 87,183 BOE/day from 85,490 BOE/day in the fourth quarter of 2012. The majority of the increase was from our Marcellus natural gas properties where our production volumes grew by approximately 40% quarter over quarter.

Compared to the first quarter of 2012, our first quarter production increased 10% or 7,993 BOE/day. Crude oil volumes increased by 12% largely due to higher production from our Fort Berthold property and natural gas volumes were up by 10% due to increased production from our Marcellus interests. These production increases helped to offset the expected production declines on our Canadian conventional natural gas assets.

Given the increase in our natural gas production, our crude oil and liquids production weighting decreased slightly to 48% in the first quarter from 49% in the fourth quarter of 2012.

Average daily production volumes for the three months ended March 31, 2013 and 2012 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2013**	**2012**	**% Change**
Crude oil (bbls/day)	38,321	34,074	12%
Natural gas liquids (bbls/day)	3,595	4,002	(10)%
Natural gas (Mcf/day)	271,602	246,686	10%
Total daily sales (BOE/day)	87,183	79,190	10%

We are pleased with our production results to date and at this point we are maintaining our 2013 production guidance with annual average production of 82,000 – 85,000 BOE/day and 2013 exit production of 84,000 – 88,000 BOE/day. This guidance does not contemplate additional acquisitions or dispositions but does reflect a non-core asset disposition in Taylorton and Turner Valley of approximately 600 BOE/day that closed subsequent to the quarter.

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 quarterly average prices from the first quarter of 2012 to the first quarter of 2013.

Pricing (average for the period)	**Q1 2013**	**Q4 2012**	**Q3 2012**	**Q2 2012**	**Q1 2012**
Benchmarks					
WTI crude oil (US$/bbl)	$ 94.37	$ 88.18	$ 92.22	$ 93.49	$ 102.93
AECO natural gas – monthly index (CDN$/Mcf)	3.08	3.06	2.19	1.83	2.52
AECO natural gas – daily index (CDN$/Mcf)	3.20	3.22	2.29	1.90	2.15
NYMEX natural gas – monthly NX3 (US$/Mcf)	3.35	3.36	2.81	2.26	2.77
US/CDN exchange rate	1.01	0.99	1.00	1.01	1.00
Enerplus selling price(1)					
Crude oil (per bbl)	$ 78.52	$ 76.75	$ 76.41	$ 74.36	$ 85.91
Natural gas liquids (per bbl)	58.58	47.31	47.81	60.11	56.77
Natural gas (per Mcf)	3.10	3.01	2.20	2.06	2.27
Average differentials (US$/bbl or US$/Mcf)					
MSW Edmonton – WTI	$ (6.95)	$ (3.32)	$ (7.21)	$ (10.12)	$ (10.49)
WCS Hardisty – WTI	(31.96)	(18.11)	(21.72)	(22.87)	(21.42)
Brent Futures (ICE) – WTI	18.24	21.81	17.22	15.38	15.40
AECO monthly – NYMEX	(0.28)	(0.31)	(0.60)	(0.40)	(0.23)
Enerplus realized differentials(1)					
U.S. crude oil – WTI	$ (6.10)	$ (5.18)	$ (12.90)	$ (13.21)	$ (15.90)
Canada crude oil – WTI	(26.97)	(15.54)	(17.41)	(23.48)	(17.97)
U.S. natural gas – NYMEX	0.12	0.34	0.34	0.41	0.37
Canada natural gas – NYMEX	(0.49)	(0.57)	(0.86)	(0.34)	(0.66)

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

Crude Oil and Natural Gas Liquids

Crude oil prices strengthened in the first two months of the quarter, with WTI reaching US$95.32/bbl in February before decreasing in March to settle at US$92.96/bbl. The softening towards the end of the first quarter was largely due to macroeconomic and political uncertainty in Europe, which put downward pressure on crude oil prices. Canadian crude differentials widened in the first quarter of 2013 due to refinery downtime and pipeline apportionments. We expect wider differentials for Canadian heavy crude oil to persist until late 2013, and perhaps longer, as we await new heavy refining capacity to come on-line.

While natural gas liquids prices in the first quarter of 2013 were comparable to 2012, we remain concerned about pricing in 2013 for ethane and propane, in particular, given tight fractionation capacity.

The average price received for our crude oil (net of transportation costs) in the first quarter of 2013 decreased by 9% to $78.52/bbl from $85.91/bbl for the same period in 2012, which was consistent with the decrease in benchmark prices. The impact of wider heavy crude oil differentials in Canada was largely offset by increased light oil production from our U.S. assets and some tightening in light sweet differentials. The improvement in our realized U.S. crude oil differential over the first quarter of 2012 is due to rail and pipeline projects that have removed transportation bottlenecks in the Fort Berthold area.

Natural Gas

Natural gas prices were stronger in the first quarter of 2013 compared to the same period in 2012 as a result of reduced dry gas capital programs sparked by the low prices over the past year. In addition, a return to more seasonal winter weather conditions compared to milder temperatures in 2012 contributed to the improvement in natural gas prices through the first quarter. Prices have continued to rise during the second quarter of 2013 with U.S. natural gas storage volumes trending below the five year average level.

For the three months ended March 31, 2013 we sold our natural gas for an average price of $3.10/Mcf (net of transportation costs) which represented a 37% increase from the prices received during the first quarter of 2012. Our realized price increase was in-line with the change in the benchmarks and reflects our natural gas sales mix, which generally includes exposure to AECO indices for our Canadian production and NYMEX indices for our U.S. production. We have historically received a premium to NYMEX on our U.S. natural gas production, in part due to the high heat content of our associated gas in Montana and North Dakota. However, the premium narrowed in the quarter compared to the first quarter of 2012, mainly due to increased natural gas supply in the Marcellus region. We expect the industry Marcellus supply points to price at roughly US$0.05/Mcf below NYMEX during 2013.

Price Risk Management

We have a price risk management program that is designed to mitigate a portion of the variability in commodity prices. The program considers our overall financial position along with the economics of our capital program and potential acquisitions. At current commodity prices our crude oil production accounts for approximately 80% of our corporate netback. As a result we continued to add crude oil hedge positions during the quarter and as of April 24, 2013 we have swapped 19,000 bbls/day for 2013 at an average price of US$100.44/bbl, representing approximately 64% of our forecasted net production after royalties. We have also swapped 4,500 bbls/day representing approximately 15% of our forecasted net production after royalties for 2014 at an average price of US$92.60/bbl.

With the increase in natural gas prices in the quarter we added additional natural gas hedge positions to provide downside protection should natural gas prices soften. As of April 24, 2013 we have downside protection on approximately 33% of our forecasted natural gas production after royalties for 2013. This protection is comprised of 51,100 Mcf/day at AECO $3.40/Mcf before premiums, 15,000 Mcf/day swapped at NYMEX US$3.45/Mcf for the first half of 2013 along with 15,000 Mcf/day swapped at NYMEX US$3.85/Mcf for the second half of 2013. For 2014 we have swapped 50,000 Mcf/day at NYMEX US$4.17/Mcf, representing approximately 25% of our forecasted net production after royalties.

The following is a summary of the financial contracts in place at April 24, 2013 expressed as a percentage of our anticipated net of royalty production volumes:

	Crude Oil (US$/bbl)(1)(2)		AECO Natural Gas(1) (CDN$/Mcf)	NYMEX Natural Gas(1) (US$/Mcf)	
	Apr 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Dec 31, 2014	Apr 1, 2013 – Dec 31, 2013	Apr 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Dec 31, 2014
Purchased Puts	–	–	$ 3.17	–	–
%	–	–	11%	–	–
Sold Puts	$ 63.09	–	–	–	–
%	18%	–	–	–	–
Swaps (fixed price)	$ 100.44	$ 92.60	$ 3.59	$ 3.72	$ 4.17
%	64%	15%	14%	8%	25%
Sold Calls	$ 130.00	–	–	–	–
%	12%	–	–	–	–
Purchased Calls	$ 104.09	–	–	–	–
%	12%	–	–	–	–

(1) Based on weighted average price (before premiums), assumed average annual production of 83,500 BOE/day for 2013 and 2014, less royalties of 21%.
(2) The majority of our crude oil positions are priced in relation to WTI.

See Note 14 for further information on our commodity hedging.

Accounting for Price Risk Management

During the first quarter of 2013, we realized cash gains of $10.9 million on our crude oil contracts and cash gains of $0.7 million on our natural gas contracts. In comparison, during the first quarter of 2012, we realized cash losses of $10.6 million on our crude oil contracts. The crude oil and natural gas cash gains in 2013 were due to contracts that provided floor protection above market prices. The cash losses in 2012 were a result of crude oil prices rising above our fixed price swap positions.

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 the end of the first quarter of 2013 the fair value of our crude oil contracts represented gains of $21.1 million, while the fair value of our natural gas contracts represented losses of $5.7 million. These gains and losses are recorded as current deferred financial assets and liabilities respectively, on our balance sheet. The change in the fair value of our crude oil and natural gas contracts during the first quarter of 2013 represented losses of $29.6 million and $9.0 million respectively. See Note 14 for further information.

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	Three months ended March 31, 2013		2012	
Cash gains/(losses):				
Crude oil	$ 10.9	$ 3.16/bbl	$ (10.6)	$ (3.42)/bbl
Natural gas	0.7	$ 0.03/Mcf	–	$ –/Mcf
Total cash gains/(losses)	$ 11.6	$ 1.47/BOE	$ (10.6)	$ (1.48)/BOE
Non-cash gains/(losses):				
Crude oil	$ (29.6)	$ (8.58)/bbl	$ (17.0)	$ (5.48)/bbl
Natural gas	(9.0)	$ (0.37)/Mcf	–	$ –/Mcf
Total non-cash gains/(losses)	$ (38.6)	$ (4.92)/BOE	$ (17.0)	$ (2.36)/BOE
Total gains/(losses)	**$ (27.0)**	**$ (3.45)/BOE**	**$ (27.6)**	**$ (3.84)/BOE**

Revenues

Crude oil and natural gas revenues were $366.2 million ($373.4 million, net of $7.2 million of transportation costs) in the first quarter of 2013, representing an increase of 8% or $27.2 million compared to $339.0 million ($345.2 million, net of $6.2 million of transportation costs) during the same period in 2012. Crude oil revenues increased slightly as higher production levels were largely offset by lower realized prices. Natural gas revenues increased due to higher production levels combined with improvements in realized prices.

Analysis of Sales Revenue[1] ($ millions)	Crude Oil	NGLs	Natural Gas	Total
Quarter ended March 31, 2012	$ 266.4	$ 20.7	$ 51.9	$ 339.0
Price variance	(25.5)	0.6	20.0	(4.9)
Volume variance	29.9	(2.3)	4.5	32.1
Quarter ended March 31, 2013	**$ 270.8**	**$ 19.0**	**$ 76.4**	**$ 366.2**

(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, 2013 royalties increased to $74.7 million from $66.7 million in the same quarter of 2012, primarily due to increased production. As a percentage of oil and gas sales, net of transportation costs, royalties in the first quarter were 20% which is unchanged from 2012. We continue to expect an average royalty rate of 21% in 2013.

Operating Expenses

Our operating expenses, which were in line with expectations, totaled $81.3 million or $10.37/BOE during the first quarter compared to $72.1 million or $10.00/BOE in the first quarter of 2012 and $72.6 million or $9.23/BOE in the fourth quarter of 2012. As expected, operating expenses were higher in 2013 with additional well servicing and repairs and maintenance activity.

We are maintaining our annual guidance of $10.70/BOE for operating costs during 2013.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three months ended March 31, 2013 and 2012. 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 and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Three months ended March 31, 2013		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	41,858 BOE/day	271,948 Mcfe/day	87,183 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[2]	$ 72.88	$ 3.75	$ 46.67
Royalties	(16.69)	(0.48)	(9.52)
Cash operating costs	(11.67)	(1.55)	(10.42)
Netback before hedging	$ 44.52	$ 1.72	$ 26.73
Cash gains/(losses)	2.89	0.03	1.47
Netback after hedging	$ 47.41	$ 1.75	$ 28.20
Netback before hedging ($ millions)	$ 167.6	$ 42.1	$ 209.7
Netback after hedging ($ millions)	**$ 178.5**	**$ 42.8**	**$ 221.3**

	Three months ended March 31, 2012		
Netbacks by Property Type	**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**

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of oil and gas transportation costs.

Our crude oil properties accounted for 80% of our corporate netback before hedging for the first quarter of 2013, compared to 84% for the same period in 2012. Crude oil netbacks after hedging per BOE during 2013 are similar to 2012 as cash hedging gains largely offset lower realized crude oil prices. Natural gas netbacks after hedging per Mcfe increased mainly due to higher realized natural gas prices.

General and Administrative Expenses

G&A expenses during the first quarter of 2013 were $24.7 million or $3.15/BOE compared to $20.7 million or $2.87/BOE in the first quarter of 2012. The $4.0 million increase in G&A in the first quarter of 2013 was mainly due to one-time charges associated with the departure of personnel, the most significant of which is the planned departure of our Chief Executive Officer.

We continue to expect cash G&A expenses of approximately $2.70/BOE for 2013.

Equity Based Compensation Expenses

Equity based compensation expenses were $6.5 million in the first quarter of 2013 compared to $4.6 million in the first quarter of 2012. These expenses include charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 13 for further details). The costs of our LTI plans are dependent on our share price and can fluctuate from period to period. Our LTI costs increased in 2013 as our share price rose 15% during the first quarter, compared to a 14% decrease during the first quarter of 2012.

We also recorded non-cash gains of $1.5 million during the quarter related to equity swaps on our LTI plans. Utilizing the equity swaps, we have effectively fixed the future settlement cost on our LTI plans at a weighted average price of $13.08 per share on 1,130,000 shares, representing approximately 60% of the notional shares outstanding under these plans.

	Three months ended March 31,	
Equity Based Compensation Expenses ($ millions)	**2013**	**2012**
LTI plans expense – cash	$ 5.5	$ 1.6
LTI plans equity swap loss/(gain) – non-cash	(1.5)	–
Stock option plan – non-cash	2.5	3.0
Total equity based compensation expenses	**$ 6.5**	**$ 4.6**

Equity Based Compensation Expenses (Per BOE)	**2013**	**2012**
LTI plans expense – cash	$ 0.70	$ 0.22
LTI plans equity swap loss/(gain) – non-cash	(0.19)	–
Stock option plan – non-cash	0.32	0.42
Total equity based compensation expenses	**$ 0.83**	**$ 0.64**

We continue to expect cash equity based compensation expenses of approximately $0.45/BOE in 2013.

Finance Expense

Interest on our senior notes and bank credit facility for the first quarter of 2013 totaled $14.2 million compared to $10.8 million in 2012. The increase is due to higher average debt levels in 2013 and an increased weighting of senior notes with higher interest rates. The increase in senior notes is a result of the $405 million private placement that closed in May 2012. Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of debt transaction costs and unrealized gains and losses resulting from the change in fair value of our interest rate swaps along with the interest component on our cross currency interest rate swap ("CCIRS"). See Note 10 for further details.

	Three months ended March 31,	
Finance Expense ($ millions)	**2013**	**2012**
Interest on senior notes and bank facility	$ 14.2	$ 10.8
Non-cash finance expense	4.2	5.0
Total finance expense	**$ 18.4**	**$ 15.8**

At March 31, 2013 approximately 68% of our debt was based on fixed interest rates compared to March 31, 2012, when approximately 41% of our debt was based on fixed interest rates.

Foreign Exchange

We recorded a foreign exchange loss of $4.4 million during the quarter compared to a gain of $5.3 million for the first quarter of 2012. During the first quarter of 2013 the Canadian dollar weakened against the U.S. dollar, which resulted in realized losses on short-term U.S. dollar advances under our bank credit facility, representing the majority of the $2.7 million realized loss. We also recorded net unrealized losses of $1.7 million during the quarter related to the period-end translation of our U.S. dollar debt and working capital, which were partially offset by unrealized gains on our CCIRS and foreign exchange swaps. See Note 11 for further details.

	Three months ended March 31,	
Foreign Exchange ($ millions)	**2013**	**2012**
Realized loss/(gain)	$ 2.7	$ (5.3)
Unrealized loss/(gain)	1.7	–
Total foreign exchange loss/(gain)	**$ 4.4**	**$ (5.3)**

Capital Investment

Capital spending for the first quarter of 2013 totaled $172.9 million compared to $317.1 million during the same period in 2012. The decrease of $144.2 million is in line with expectations given our moderated capital spending plans for 2013 and our annual capital spending guidance of $685 million. Spending during the quarter was predominantly focused on our crude oil properties with $77.4 million being invested in our Fort Berthold crude oil property and $47.2 million being directed to oil properties in Canada. Spending on our natural gas assets included $23.2 million on our deep basin properties in Canada along with $12.6 million on our Marcellus assets.

Property and land acquisitions for the first quarter of 2013 totaled $4.0 million, primarily for the purchase of additional undeveloped land interests in Canada and the U.S. around our existing holdings. In comparison, during the first quarter of 2012, we spent $33.0 million which included undeveloped land acquisitions of $15.5 million and US$16.1 million towards our Marcellus carry obligation. This carry obligation was fully satisfied in the third quarter of 2012.

Dispositions

During the first quarter of 2013 we completed minor non-core asset dispositions for proceeds of approximately $1.3 million. Subsequent to the quarter, we disposed of non-core oil assets in Taylorton and Turner Valley with production of approximately 600 BOE/day for proceeds of approximately $58 million. In 2012, first quarter dispositions included the sale of undeveloped land interests to Laricina Energy Ltd. in exchange for common shares in the company valued at $30.0 million along with other non-core assets for proceeds of approximately $22.6 million.

Our total capital investment activity for the first quarter of 2013 and 2012 is outlined below:

	Three months ended March 31,	
Capital Investment ($ millions)	**2013**	**2012**
Capital spending	$ 172.9	$ 317.1
Office capital	1.4	2.5
Sub-total	$ 174.3	$ 319.6
Property and land acquisitions	$ 4.0	$ 33.0
Property dispositions	(1.3)	(52.6)
Sub-total	$ 2.7	$ (19.6)
Total net capital investment	**$ 177.0**	**$ 300.0**

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, 2013 DD&A increased to $126.9 million, compared to $118.5 million during the same period in 2012, primarily due to higher production from our U.S. operations resulting in higher depletion expense.

On a per BOE basis, depletion decreased to $16.17/BOE from $16.45/BOE in 2012 as a result of reserve additions recorded at year end 2012.

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, 2013 resulted in an unrealized gain of $1.5 million, compared to an unrealized loss of $4.2 million for the same period last year. During the first quarter, we also sold certain marketable securities for proceeds of $1.9 million recognizing a gain of $0.2 million. See Note 7 for further information.

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 $614.1 million at March 31, 2013 compared to $599.7 million at December 31, 2012. See Note 9 for further information.

Taxes

Current Income Taxes

We recorded a current tax expense of $1.3 million for the first quarter of 2013 compared to $0.7 million for the same period in 2012. Our current tax expense is comprised mainly of Alternative Minimum Tax ("AMT") payable with respect to our U.S. subsidiary. We expect to recover AMT in future years as an offset to regular U.S. income taxes otherwise payable.

We expect to pay U.S. cash taxes of approximately 3% of U.S. cash flow until 2016. We currently do not expect to pay material cash taxes in Canada until after 2016. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and disposition activity.

Deferred Income Taxes

We recorded a deferred tax expense of $6.1 million for the first quarter of 2013 compared to a recovery of $11.1 million for the same period in 2012. The increase in deferred income tax expense is due to higher income during 2013.

Net Income/(Loss)

In the first quarter we reported a net loss of $5.2 million compared to a net loss of $33.8 million in the same period in 2012. Higher oil and gas sales helped to increase earnings in 2013 however, non-cash mark to market losses of $38.6 million on our commodity derivatives, which resulted from higher forecast commodity prices at March 31, negatively impacted earnings.

The $33.8 million net loss in the first quarter of 2012 was largely driven by $86.9 million of non-cash impairment charges on our assets, partially offset by $24.1 million of gains recorded on asset dispositions.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

The following table provides a geographical analysis of key operating and financial results for the three months ended March 31, 2013 and 2012.

	Three months ended March 31, 2013			Three months ended March 31, 2012		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	19,169	19,152	38,321	20,602	13,472	34,074
Natural gas liquids (bbls/day)	3,116	479	3,595	3,797	205	4,002
Natural gas (Mcf/day)	177,809	93,793	271,602	208,114	38,572	246,686
Total average daily production (BOE/day)	51,919	35,264	87,183	59,084	20,106	79,190
Pricing(1)						
Crude oil (per bbl)	$ 68.00	$ 89.06	$ 78.52	$ 85.06	$ 87.20	$ 85.91
Natural gas liquids (per bbl)	62.33	34.22	58.58	57.14	49.96	56.77
Natural gas (per Mcf)	2.89	3.50	3.10	2.11	3.14	2.27
Capital Expenditures						
Capital spending	$ 83.0	$ 89.9	$ 172.9	$ 111.2	$ 205.9	$ 317.1
Property and land acquisitions	2.6	1.4	4.0	11.4	21.6	33.0
Property dispositions	(1.3)	–	(1.3)	(30.7)	(21.9)	(52.6)
Revenues						
Oil and gas sales(1)	$ 181.7	$ 184.5	$ 366.2	$ 220.0	$ 119.0	$ 339.0
Royalties(2)	(26.3)	(48.4)	(74.7)	(35.7)	(31.0)	(66.7)
Commodity derivatives gain/(loss)	(27.0)	–	(27.0)	(27.6)	–	(27.6)
Expenses						
Operating	$ 66.1	$ 15.2	$ 81.3	$ 60.1	$ 12.0	$ 72.1
General and administrative	21.4	3.3	24.7	17.1	3.6	20.7
Equity based compensation	6.0	0.5	6.5	4.6	–	4.6
Depletion, depreciation and amortization	64.3	62.6	126.9	80.7	37.8	118.5
Current income tax expense/(recovery)	–	1.3	1.3	(0.6)	1.3	0.7

(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

Oil and gas sales were up slightly in the first quarter of 2013 mainly due to higher natural gas production volumes compared to the fourth quarter of 2012. During 2012 oil and gas sales were relatively flat as increasing production volumes were offset by lower realized commodity prices. During 2011 we saw higher crude oil prices and declining natural gas prices combined with lower production levels, which resulted in fluctuating oil and gas sales throughout the year.

Quarterly Financial Information (CDN$ millions, except per share amounts)	Oil and Gas Sales[1]	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2013				
First Quarter	$ 366.2	$ (5.2)	$ (0.03)	$ (0.03)
2012				
Fourth Quarter	$ 360.7	$ (158.7)	$ (0.80)	$ (0.80)
Third Quarter	324.9	(63.5)	(0.32)	(0.32)
Second Quarter	314.4	100.3	0.51	0.51
First Quarter	339.0	(33.8)	(0.18)	(0.18)
Total	**$ 1,339.0**	**$ (155.7)**	**$ (0.80)**	**$ (0.80)**
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**

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

LIQUIDITY AND CAPITAL RESOURCES

We continue to manage our balance sheet to preserve our financial flexibility in the context of the current commodity price environment, dividend levels and our capital spending plans for the year. Improving natural gas prices and additional non-core asset divestments in 2013 are expected to further reduce our funding shortfall which we originally estimated at $200.0 million for the year. We are continuing to invest in our core producing assets and are pursuing other measures to help manage the funding shortfall and support our growth plans, such as the partial sale or joint venture of interests including those in the Duvernay and Montney.

Total debt at March 31, 2013, including the current portion, was $1,138.3 million compared to $1,069.6 million at December 31, 2012. Total debt at March 31, 2013 was comprised of $314.3 million of bank indebtedness and $824.0 million of senior notes. We have $685.7 million of available capacity on our bank credit facility at March 31, 2013 and a trailing twelve month debt to funds flow ratio of 1.7x.

Our working capital deficiency at March 31, 2013, excluding current deferred financial assets and credits, was $163.1 million compared to $167.2 million at December 31, 2012. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our adjusted payout ratio, which is calculated as dividends (net of our stock dividends and DRIP proceeds) plus capital spending and office capital divided by funds flow, was 126% for the first quarter of 2013 compared to 254% for the first quarter of 2012. The decrease in our adjusted payout ratio was a result of lower capital spending and higher funds flow combined with the reduction in our monthly dividend from $0.18 to $0.09 in the second quarter of 2012.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	March 31, 2013	December 31, 2012
Long-term debt to funds flow (12 month trailing)(1)	1.7 x	1.7 x
Funds flow to interest expense (12 month trailing)(2)	11.6 x	12.1 x
Long-term debt to long-term debt plus equity(1)	27%	26%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.
(2) Interest expense is finance expense excluding non-cash items.

At March 31, 2013 we were in compliance with all covenants under our bank credit facility and senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

Dividends

We reported a total of $53.8 million ($0.27/share) in dividends to our shareholders in the first quarter of 2013, which included $10.1 million of non-cash amounts related to our Stock Dividend Program ("SDP"). We continue to assess our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions and do not anticipate any changes at this time.

Our SDP allows shareholders to elect to receive their dividends in the form of shares instead of cash should they choose. Currently approximately 20% of our shareholders participate in the SDP representing $3.5 million of dividends per month. As with our previous DRIP, the SDP will serve as a source of capital by allowing us to retain cash that would otherwise be paid out as dividends.

Shareholders' Capital

During the first quarter of 2013, a total of 779,000 shares were issued for $10.1 million pursuant to our Stock Dividend Program and stock option plan. A total of 595,000 shares were issued for $13.3 million under our former DRIP and the stock option plan for the same period in 2012. See Note 13 for further information.

We had 199,463,000 shares outstanding at March 31, 2013 compared to 196,463,000 shares outstanding at March 31, 2012 and 198,684,000 at December 31, 2012. The weighted average basic number of shares outstanding for the three months ended March 31, 2013 was 199,031,000 (2012 – 189,844,000). At May 9, 2013 we had 199,741,000 shares outstanding.

2013 GUIDANCE

A summary of our 2013 guidance is below. This guidance reflects acquisition and divestment activity to date but does not contemplate further potential transactions.

Summary of 2013 Expectations	Target
Average annual production	82,000 - 85,000 BOE/day
Exit rate production	84,000 - 88,000 BOE/day
Capital spending	$685 million
Production mix (volumes)	50% crude oil and liquids, 50% natural gas
Average royalty rate (% of gross sales, net of transportation)	21%
Operating costs	$10.70/BOE
G&A expenses – cash	$2.70/BOE
Equity based compensation expenses – cash	$0.45/BOE
Cash taxes (% of U.S. funds flow)	~3%
Average interest and financing costs	5%

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at March 31, 2013, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2013 and ended March 31, 2013 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 2013 average production volumes and the anticipated production mix; the results from our 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 2013 and its impact on our production level and land holdings; potential future asset impairments and reversals; the amount of our future abandonment and reclamation costs and decommissioning liabilities; future environmental expenses; our future 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, and use of proceeds from, 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, operating and working capital 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 the Annual MD&A and in our other public filings).

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.

Statements

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	March 31, 2013	December 31, 2012
Assets			
Current assets			
Cash		$ 12,553	$ 5,200
Accounts receivable		156,375	150,372
Deferred financial assets	14	32,195	54,165
Other current		15,440	15,068
		$ 216,563	$ 224,805
Exploration and evaluation assets	4	$ 800,302	$ 773,820
Property, plant and equipment	5	4,333,350	4,242,447
Goodwill		154,482	151,390
Deferred financial assets	14	11,059	8,013
Other assets	7	11,575	11,687
Total Assets		$ 5,527,331	$ 5,412,162
Liabilities			
Current liabilities			
Accounts payable		$ 283,019	$ 274,387
Dividends payable		17,952	17,882
Current portion of long-term debt	8	46,514	45,566
Deferred financial credits	14	33,671	18,522
		$ 381,156	$ 356,357
Long-term debt	8	$ 1,091,801	$ 1,023,999
Deferred financial credits	14	17,108	17,127
Deferred tax liability		378,400	365,473
Decommissioning liability	9	614,140	599,652
		$ 2,101,449	$ 2,006,251
Total Liabilities		$ 2,482,605	$ 2,362,608
Equity			
Shareholders' capital	13	$ 3,828,172	$ 3,818,043
Contributed surplus	13	38,613	36,088
Accumulated deficit		(795,784)	(736,761)
Accumulated other comprehensive income/(loss)		(26,275)	(67,816)
		$ 3,044,726	$ 3,049,554
Total Liabilities & Equity		$ 5,527,331	$ 5,412,162

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income (loss) and Comprehensive Income (loss)

Three months ended March 31 (CDN$ thousands) unaudited	**Note**	**2013**	**2012**
Revenues			
Oil and gas sales		$ 373,425	$ 345,151
Royalties		(74,668)	(66,726)
Commodity derivative instruments (loss)	14	(27,055)	(27,654)
		$ 271,702	$ 250,771
Expenses			
Operating		$ 81,348	$ 72,063
General and administrative		24,679	20,720
Equity based compensation	13	6,530	4,575
Transportation		7,197	6,152
Depletion, depreciation and amortization	5	126,878	118,518
Impairments	6	–	86,906
Foreign exchange loss/(gain)	11	4,352	(5,320)
Finance	10	18,376	15,798
Asset disposition (gain)	7	(217)	(24,100)
Other expense/(income)		342	(342)
		$ 269,485	$ 294,970
Income/(loss) before taxes		$ 2,217	$ (44,199)
Current tax expense/(recovery)	12	1,307	703
Deferred tax expense/(recovery)	12	6,148	(11,081)
Net Income/(loss)		$ (5,238)	$ (33,821)
Other Comprehensive Income			
Change due to marketable securities (net of tax)	7		
Unrealized gains/(losses)		$ 1,547	$ (4,176)
Realized gains reclassified to net income/(loss)		(190)	–
Change in cumulative translation adjustment		40,184	(28,984)
Other Comprehensive Income/(loss), net of tax		$ 41,541	$ (33,160)
Total Comprehensive Income/(loss)		$ 36,303	$ (66,981)
Net income/(loss) per share			
Basic		$ (0.03)	$ (0.18)
Diluted		$ (0.03)	$ (0.18)
Weighted average number of shares outstanding (thousands)	13		
Basic		199,031	189,844
Diluted		199,031	189,844

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	**2013**	**2012**
Shareholders' Capital		
Balance, beginning of year	$ 3,818,043	$ 3,442,364
Public offering	–	330,618
Stock Option Plan – cash	21	747
Stock Option Plan – non cash	2	644
Dividend Reinvestment Plan	–	12,533
Stock Dividend Program	10,106	–
Balance, end of period	$ 3,828,172	$ 3,786,906
Contributed Surplus		
Balance, beginning of year	$ 36,088	$ 26,910
Stock Option Plan – exercised	(2)	(644)
Stock Option Plan – expensed	2,527	2,992
Balance, end of period	$ 38,613	$ 29,258
Accumulated Deficit		
Balance, beginning of year	$ (736,761)	$ (279,467)
Net income/(loss)	(5,238)	(33,821)
Dividends to shareholders	(53,785)	(105,995)
Balance, end of period	$ (795,784)	$ (419,283)
Accumulated other comprehensive income		
Balance, beginning of year	$ (67,816)	$ 87,172
Changes due to marketable securities (net of tax)		
Unrealized gains/(losses)	1,547	(4,176)
Realized gains reclassified to net income	(190)	–
Change in cumulative translation adjustment	40,184	(28,984)
Balance, end of period	$ (26,275)	$ 54,012
Total Equity	$ 3,044,726	$ 3,450,893

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

Three months ended March 31 (CDN$ thousands) unaudited		**2013**		**2012**
Operating Activities				
Net income/(loss)	$	(5,238)	$	(33,821)
Non-cash items add/(deduct):				
Depletion, depreciation and amortization		126,878		118,518
Impairments		–		86,906
Change in fair value of derivative instruments		34,054		21,824
Deferred tax expense/(recovery)		6,148		(11,081)
Foreign exchange loss/(gain) on U.S. dollar debt and working capital		4,320		(2,365)
Accretion expense		3,509		3,453
Equity based compensation – Stock Option Plan		2,527		2,992
Amortization of debt transaction costs		615		380
Asset disposition gain		(217)		(24,100)
Funds Flow	$	172,596	$	162,706
Decommissioning expenditures		(3,378)		(7,298)
Changes in non-cash operating working capital		(7,987)		(86,427)
Cash flow from operating activities	$	161,231	$	68,981
Financing Activities				
Issuance of shares	$	21	$	343,898
Cash dividends		(43,679)		(105,995)
Change in bank debt		55,419		(229)
Changes in non-cash financing working capital		70		2,755
Cash flow from financing activities	$	11,831	$	240,429
Investing Activities				
Capital expenditures	$	(174,373)	$	(319,570)
Property and land acquisitions		(3,967)		(33,020)
Property dispositions		1,331		22,611
Sale of equity investments		1,883		–
Changes in non-cash investing working capital		10,723		14,712
Cash flow from investing activities	$	(164,403)	$	(315,267)
Effect of exchange rate changes on cash	$	(1,306)	$	1,681
Change in cash	$	7,353	$	(4,176)
Cash, beginning of year		5,200		5,629
Cash, end of period	$	12,553	$	1,453
Supplementary Cash Flow Information				
Cash income taxes paid/(received)	$	(5,246)	$	14,438
Cash interest paid	$	2,874	$	3,163

See accompanying notes to the Condensed Consolidated Financial Statements

Notes

Notes to Consolidated Financial Statements

(unaudited)

1. REPORTING ENTITY

These interim condensed consolidated financial statements ("interim Consolidated Financial Statements") and notes 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. Enerplus 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 9, 2013.

2. BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") for the three months ended March 31, 2013, and the 2012 comparative periods. These interim Consolidated Financial Statements have been prepared in accordance with IAS 34, "Interim Financial Reporting" and do not include all the necessary annual disclosures as prescribed by IFRS. These interim Consolidated Financial Statements should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2012. There have been no changes to the use of estimates or judgments since December 31, 2012.

3. SIGNIFICANT ACCOUNTING POLICIES

On January 1, 2013, Enerplus adopted the following new accounting standards that were issued by the IASB. The adoption of these standards did not have a material impact on Enerplus' interim Consolidated Financial Statements.

- IFRS 7 *Financial Instruments Disclosures*
- IFRS 10 *Consolidated Financial Statements*
- IFRS 11 *Joint Arrangements*.
- IFRS 12 *Disclosure of Interests in Other Entities*
- IFRS 13 *Fair Value Measurement*
- IAS 27 *Consolidation and Separate Financial Statements*
- IAS 28 *Investments in Joint Ventures*

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

Carrying value ($ thousands)	**E&E assets**
As at December 31, 2012	$ 773,820
Capital spending and acquisitions	28,700
Transfers to Property, Plant and Equipment	(11,863)
Foreign currency translation adjustment	9,645
As at March 31, 2013	**$ 800,302**

As at March 31, 2013 the E&E asset balance of $800,302,000 (December 31, 2012 – $773,820,000) consists of undeveloped lands and assets that management has not fully evaluated for technical feasibility and commercial viability.

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

Carrying value before accumulated depletion and depreciation ($ thousands)	Developed and Producing ("D&P assets")	Office and other	Total
As at December 31, 2012	$ 6,684,154	$ 82,588	$ 6,766,742
Capital spending and acquisitions	148,211	1,424	149,635
Transfers from E&E assets	11,863	–	11,863
Change in decommissioning costs (Note 9)	13,690	–	13,690
Dispositions	(1,346)	–	(1,346)
Foreign currency translation adjustment	51,457	219	51,676
As at March 31, 2013	**$ 6,908,029**	**$ 84,231**	**$ 6,992,260**

Accumulated Depletion and Depreciation	D&P assets	Office and other	Total
As at December 31, 2012	$ 2,463,903	$ 60,392	$ 2,524,295
Depletion and Depreciation	125,265	1,613	126,878
Foreign currency translation adjustment	7,663	74	7,737
As at March 31, 2013	**$ 2,596,831**	**$ 62,079**	**$ 2,658,910**

Net carrying value	D&P assets	Office and other	Total
As at December 31, 2012	$ 4,220,251	$ 22,196	$ 4,242,447
As at March 31, 2013	**$ 4,311,198**	**$ 22,152**	**$ 4,333,350**

6. IMPAIRMENT

	Three months ended March 31	
($ thousands)	2013	2012
D&P assets	$ –	$ 86,906
Impairment expense	**$ –**	**$ 86,906**

7. OTHER ASSETS

Other assets of $11,575,000 (December 31, 2012 – $11,687,000) represent Enerplus' marketable securities portfolio. During the three months ended March 31, 2013 Enerplus sold certain marketable securities for proceeds of $1,883,000 recognizing a gain of $217,000. In connection with these sales, realized gains of $190,000 net of tax ($217,000 before tax) were reclassified from accumulated other comprehensive income to net income.

For the three months ended March 31, 2013 the change in fair value of these investments represented unrealized gains of $1,547,000 net of tax ($1,771,000 before tax). For the three months ended March 31, 2012 the change in fair value of these investments represented unrealized losses of $4,176,000 net of tax ($4,792,000 before tax).

8. DEBT

($ thousands)	March 31, 2013	December 31, 2012
Current:		
Senior notes	$ 46,514	$ 45,566
	$ 46,514	$ 45,566
Long-term:		
Bank credit facility	$ 314,334	$ 260,950
Senior notes	777,467	763,049
	$ 1,091,801	$ 1,023,999
Total debt	**$ 1,138,315**	**$ 1,069,565**

Senior Notes

The Company's outstanding senior notes at March 31, 2013 are detailed below:

($ thousands)

Issue Date	Interest Payment	Principal Repayment	Coupon	Original Principal	Remaining Principal	CDN$ Carrying Value
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2019	4.34%	CDN$30,000	CDN$30,000	$ 30,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	20,312
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$355,000	360,538
June 18, 2009	June 18 and Dec 18	Bullet payment on June 18, 2015	6.37%	CDN$40,000	CDN$40,000	40,000
June 18, 2009	June 18 and Dec 18	Bullet payment on June 18, 2015	6.82%	US$40,000	US$40,000	40,624
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$225,000	228,510
Oct 1, 2003	April 1 and Oct 1	5 equal annual installments beginning Oct 1, 2011	5.46%	US$54,000	US$32,400	32,905
June 19, 2002	June 19 and Dec 19	5 equal annual installments beginning June 19, 2010	6.62%	US$175,000	US$70,000	71,092
					Total Carrying Value	**$ 823,981**
					Current portion	**$ 46,514**
					Long-term portion	**$ 777,467**

9. DECOMMISSIONING LIABILITY

Enerplus has estimated the net present value of its decommissioning liability to be $614,140,000 at March 31, 2013 compared to $599,652,000 at December 31, 2012, based on a total undiscounted liability of $748,828,000 and $659,714,000 respectively. The decommissioning liability was calculated using a risk free rate of 2.50% at March 31, 2013 (December 31, 2012 – 2.36%).

($ thousands)	Three months ended March 31, 2013	Year ended December 31, 2012
Decommissioning liability, beginning of year	$ 599,652	$ 563,763
Change in estimates	11,901	69,822
Property acquisition and development activity	1,789	5,559
	$ 13,690	$ 75,381
Dispositions	–	(33,584)
Decommissioning expenditures	(3,378)	(19,905)
Accretion	3,509	13,522
Foreign currency translation adjustment	667	475
Decommissioning liability, end of period	**$ 614,140**	**$ 599,652**

10. FINANCE EXPENSE

	Three months ended March 31	
($ thousands)	2013	2012
Realized:		
Interest on bank debt and senior notes	$ 14,184	$ 10,848
Unrealized:		
Cross currency interest rate swap (gain)/loss	333	1,449
Interest rate swap (gain)/loss	(265)	(332)
Debt transaction cost amortization	615	380
Accretion of decommissioning liability	3,509	3,453
Finance expense	**$ 18,376**	**$ 15,798**

11. FOREIGN EXCHANGE

	Three months ended March 31	
($ thousands)	2013	2012
Realized:		
Foreign exchange (gain)/loss	$ 2,732	$ (5,280)
Unrealized:		
Translation of U.S. dollar debt and working capital (gain)/loss	4,320	(2,365)
Cross currency interest rate swap (gain)/loss	(1,012)	2,061
Foreign exchange swaps (gain)/loss	(1,688)	264
Foreign exchange (gain)/loss	**$ 4,352**	**$ (5,320)**

12. INCOME TAXES

($ thousands)	Three months ended March 31 2013	2012
Current tax expense/(recovery)		
Canada	$ 4	$ (633)
U.S.	1,303	1,336
Total current tax expense/(recovery)	$ 1,307	$ 703
Deferred tax expense/(recovery)	6,148	(11,081)
Total income tax expense/(recovery)	**$ 7,455**	**$ (10,378)**

13. SHAREHOLDERS' CAPITAL

(a) Share Capital

	Three months ended March 31		Year ended December 31	
	2013		2012	
Authorized unlimited number of common shares **Issued:** (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	198,684	$ 3,818,043	181,159	$ 3,442,364
Issued for cash:				
Public offerings	–	–	14,709	330,618
Dividend reinvestment plan	–	–	955	19,150
Stock option plan	1	21	68	1,180
Non-cash:				
Stock dividend program	778	10,106	1,793	23,612
Stock option plan	–	2	–	1,119
Balance, end of period	**199,463**	**$ 3,828,172**	**198,684**	**$ 3,818,043**

(b) Dividends

($ thousands)	Three months ended March 31 2013	2012
Cash dividends	$ 43,679	$ 105,995
Stock dividends	10,106	–
Dividends to shareholders	**$ 53,785**	**$ 105,995**

(c) Equity based compensation

($ thousands)	Three months ended March 31 2013	2012
Cash:		
Long term incentive plans expense	$ 5,518	$ 1,583
Non-Cash:		
Stock option plan expense	2,527	2,992
Equity total return swap gain	(1,515)	–
Equity based compensation expense	**$ 6,530**	**$ 4,575**

(i) Long-Term Incentive Plans

Enerplus' long-term incentive plans include its PSU, RSU and DSU plans. For the three months ended March 31, 2013 the Company recorded cash compensation costs of $5,518,000 (March 31, 2012 – $1,584,000) for these plans which was included in equity based compensation. At March 31, 2013 the long-term incentive plans had a liability balance of $13,281,000 (December 31, 2012 – $13,316,000) which is included in accounts payable on the Consolidated Balance Sheets.

The following table summarizes the PSU, RSU and DSU activity for the three months ended March 31, 2013:

(thousands of units)	PSUs	RSUs	DSUs
Units outstanding:			
Beginning of year	605	963	35
Granted	344	425	78
Vested	–	(378)	–
Forfeited	(12)	(35)	–
End of period	**937**	**975**	**113**

(ii) 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, 2013	December 31, 2012
Dividend yield(1)	8.0%	8.2%
Volatility(1)	27.80%	28.35%
Risk-free interest rate	1.50%	1.35%
Forfeiture rate	10.0%	10.0%
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.

The weighted average grant date fair value of options granted during the three months ended March 31, 2013 was $1.29 (March 31, 2012 – $2.54). At March 31, 2013, 4,803,000 options were exercisable at a weighted average exercise price of $25.77 resulting in an aggregate intrinsic value of $134,000 (March 31, 2012 – $4,017,000). These options have a weighted average remaining contractual term of 4.3 years.

For the three months ended March 31, 2013, a total of 1,000 options were exercised at a weighted average exercise price of $14.14. The weighted average share price during the period was $13.74.

For the three months ended March 31, 2013, Enerplus expensed a total of $2,527,000 related to its stock option plan. The total unamortized fair value of outstanding options of $10,649,000 will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Three months ended March 31, 2013		Year ended December 31, 2012	
	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	10,768	$ 22.11	5,098	$ 29.41
Granted	5,802	13.96	7,313	19.00
Exercised	(1)	14.14	(68)	17.35
Forfeited	(265)	22.17	(1,056)	24.92
Expired	–	–	(519)	44.67
End of period	**16,304**	**$ 19.21**	**10,768**	**$ 22.11**
Options exercisable at the end of period	**4,803**	**$ 25.77**	**2,558**	**$ 27.20**

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

The following tables summarize the Contributed Surplus activity for the three months ended March 31, 2013 and the ending balances as at March 31, 2013:

($ thousands)	Three months ended March 31, 2013	Year ended December 31, 2012
Balance, beginning of year	$ 36,088	$ 26,910
Stock Option Plan – exercised	(2)	(1,119)
Stock Option Plan – expensed	2,527	10,297
Balance, end of period	**$ 38,613**	**$ 36,088**

($ thousands)	March 31, 2013	December 31, 2012
Cancelled shares	$ 3,795	$ 3,795
Stock Option Plan	34,818	32,293
Balance, end of period	**$ 38,613**	**$ 36,088**

(d) Basic and Diluted Earnings Per Share

Net income/(loss) per share has been determined based on the following:

	Three months ended March 31	
(thousands of shares)	2013	2012
Weighted average shares	199,031	189,844
Dilutive impact of options(1)	–	–
Diluted shares	**199,031**	**189,844**

(1) For the three months ended March 31, 2013 and March 31, 2012 options are anti-dilutive as their conversion to shares would not increase the loss per share.

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

The carrying value of cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value at March 31, 2013 and December 31, 2012 due to their short term nature. At March 31, 2013 the combined fair values of Enerplus' senior notes was $916,957,000 and the carrying amount was $823,981,000 (December 31, 2012 – fair value of $896,871,000 and carrying value of $808,615,000). 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.

The following table summarizes the fair value as at March 31, 2013 and change in fair value for the three months ended March 31, 2013.

Deferred financial assets/(liabilities) ($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Equity Swaps	Commodity Derivative Instruments		Total
						Oil	Gas	
Beginning of period	$ (478)	$ (34,162)	$ 7,589	$ (853)	$ 412	$ 50,672	$ 3,349	$ 26,529
Change in fair value gain/(loss)	265(1)	680(2)	1,688(3)	409(4)	1,515(5)	(29,577)(6)	(9,034)(6)	(34,054)
End of period	**$ (213)**	**$ (33,482)**	**$ 9,277**	**$ (444)**	**$ 1,927**	**$ 21,095**	**$ (5,685)**	**$ (7,525)**
Balance Sheet Classification:								
Current assets	$ –	$ 1,299	$ 50	$ –	$ 352	$ 30,111	$ 383	$ 32,195
Non-current assets	–	257	9,227	–	1,575	–	–	11,059
Current liabilities	(213)	(17,930)	–	(444)	–	(9,016)	(6,068)	(33,671)
Non-current liabilities	–	(17,108)	–	–	–	–	–	(17,108)
Total	**$ (213)**	**$ (33,482)**	**$ 9,277**	**$ (444)**	**$ 1,927**	**$ 21,095**	**$ (5,685)**	**$ (7,525)**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $1,012) and finance expense (loss of $333).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in equity based compensation.
(6) Recorded in commodity derivative instruments (see below).

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

($ thousands)	Three months ended March 31 2013	2012
Change in fair value gain/(loss)	$ (38,611)	$ (17,026)
Net realized cash gain/(loss)	11,556	(10,628)
Commodity derivative instruments gain/(loss)	**$ (27,055)**	**$ (27,654)**

(c) Price Risk Management

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

The following tables summarize Enerplus' price risk management positions at April 24, 2013:

Crude Oil Instruments:

Instrument Type	bbls/day	US$/bbl[1]
Apr 1, 2013 – Dec 31, 2013		
WTI Swap	19,000	100.44
WTI Purchased Call	3,500	104.09
WTI Sold Put	5,500	63.09
WTI Sold Call	3,500	130.00
Apr 1, 2013 – Apr 30, 2013		
WCS – WTI Differential Swap	500	(24.50)
May 1, 2013 – Dec 31, 2013		
WCS – WTI Differential Swap	2,000	(21.56)
Jul 1, 2013 – Dec 31, 2013		
MSW – WTI Differential Swap	500	(5.90)
Jan 1, 2014 – Dec 31, 2014		
WTI Swap	4,500	92.60

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

Natural Gas Instruments:

Instrument Type	MMcf/day	CDN$/Mcf	US$/Mcf
Apr 1, 2013 – Jun 30, 2013			
AECO Swap	28.4	3.54	
AECO Purchased Put	22.7	3.17	
Jul 1, 2013 – Dec 31, 2013			
AECO Swap	28.4	3.61	
AECO Purchased Put	22.7	3.17	
Apr 1, 2013 – Jun 30, 2013			
NYMEX Swap	15.0		3.45
Jul 1, 2013 – Dec 31, 2013			
NYMEX Swap	15.0		3.85
Jan 1, 2014 – Dec 31, 2014			
NYMEX Swap	50.0		4.17

Physical Natural Gas contracts:

Instrument Type	MMcf/day	CDN$/Mcf
Apr 1, 2013 – Oct 31, 2013		
Fixed Price	10.0	2.91
Apr 1, 2013 – Dec 31, 2013		
Fixed Price	12.8	3.08
Apr 1, 2013 – Dec 31, 2013		
AECO-NYMEX Basis	29.4	(0.67)
Jan 1, 2014 – Oct 31, 2014		
AECO-NYMEX Basis	48.5	(0.69)
Jan 1, 2014 – Oct 31, 2014		
Fixed Price	5.0	3.53

Electricity Instruments:

Instrument Type	MWh	CDN$/Mwh
Apr 1, 2013 – Dec 31, 2013		
AESO Power Swap(1)	12.0	63.81
Jan 1, 2014 – Dec 31, 2014		
AESO Power Swap(1)	12.0	53.69
Jan 1, 2015 – Dec 31, 2015		
AESO Power Swap(1)	6.0	50.38

(1) Alberta Electrical System Operator (“AESO”) fixed pricing.

BOARD OF DIRECTORS

Douglas R. Martin(1)(2)
President
Corporate Director
Calgary, Alberta

David H. Barr(9)(11)
Corporate Director
The Woodlands, Texas

Edwin V. Dodge(9)(12)
Corporate Director
Vancouver, British Columbia

James B. Fraser(7)(11)
Corporate Director
Polson, Montana

Robert B. Hodgins(3)(6)
Corporate Director
Calgary, Alberta

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

Susan M. MacKenzie(7)(10)
Corporate Director
Calgary, Alberta

Donald J. Nelson(3)(9)
President
Fairway Resources, Inc.
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(7)
President
Seth Consultants Ltd.
Calgary, Alberta

Sheldon B. Steeves(5)(11)
Corporate Director
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, Business Development and New Plays

H. Gordon Love
Vice President, Technical & Operations Services

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

Brien A. Perry
Vice President, Human Resources

Christopher M. Stephens
Vice President, Canadian Assets

P. Scott Walsh
Vice President, Information Systems

Kenneth W. Young
Vice President, Land

Michael R. Politeski
Controller, Finance

Edward L. McLaughlin
President, Enerplus Resources (USA) Corporation

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

AUDITORS

Deloitte 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

U.S. OFFICE

950 17th Street, Suite 2200
Denver, Colorado 80202

Telephone: 720.279.5500
Fax: 720.279.5550

ABBREVIATIONS

AECO	a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices
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.
D&P	developed and producing
E&E	exploration and evaluation
IFRS	International Financial Reporting Standards
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf	million cubic feet
MWh	megawatt hour(s) of electricity
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
OCI	other comprehensive income
SDP	stock dividend program
WCS	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

enerPLUS

The Dome Tower
3000, 333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1
Toll Free 1.800.319.6462
Fax 403.298.2211

investorrelations@enerplus.com

www.enerplus.com

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE