MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results is dated May 7, 2015 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three months ended March 31, 2015 and 2014 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2014 and 2013 and for the years ended December 31, 2014, 2013 and 2012 (the "Financial Statements"); and
- our MD&A for the year ended December 31, 2014 (the "Annual MD&A").

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. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" below for further information.

BASIS OF PRESENTATION

The Interim Financial Statements and notes have been prepared in accordance with U.S. GAAP including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included in 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. BOE and Mcfe measures 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 unless otherwise stated. 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.

In accordance with U.S. GAAP, oil and gas sales are presented net of royalties in our Interim Financial Statements. Under International Financial Reporting Standards, industry standard is to present oil and gas sales before deduction of royalties and as such this MD&A presents production, oil and gas sales, and BOE measures on this basis to remain comparable with our peers.

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 U.S. GAAP and therefore may not be comparable with the calculation of similar measures by other entities:

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating costs and transportation.

Calculation of Netback ($ millions)	Three months ended March 31, 2015	2014
Oil and natural gas sales	$ 244.1	$ 495.0
Less:		
Royalties	(39.1)	(87.3)
Production taxes	(10.8)	(19.9)
Cash operating costs(1)	(86.8)	(79.8)
Transportation	(26.5)	(22.3)
Netback before hedging	$ 80.9	$ 285.7
Cash gains/(losses) on derivative instruments	86.8	(15.3)
Netback after hedging	$ 167.7	$ 270.4

(1) Operating costs adjusted to exclude non-cash losses on fixed price electricity swaps of $0.9 million in the three months ended March 31, 2015 and $0.1 million in the three months ended March 31, 2014.

"Funds Flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. Funds flow is calculated as net cash provided by operating activities before asset retirement obligation expenditures and changes in non-cash operating working capital.

Reconciliation of Cash Flow from Operating Activities to Funds Flow ($ millions)	Three months ended March 31, 2015	2014
Cash flow from operating activities	$ 131.1	$ 140.4
Asset retirement obligation expenditures	3.9	4.3
Changes in non-cash operating working capital	(25.8)	75.8
Funds flow	$ 109.2	$ 220.5

"Debt to Funds Flow Ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The debt to funds flow ratio is calculated as total debt net of cash divided by a trailing 12 months of funds flow. This measure is not equivalent to Debt to EBITDA and is not used by Enerplus to determine compliance with financial covenants.

"Adjusted Payout Ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends plus capital and office expenditures divided by funds flow.

Calculation of Adjusted Payout Ratio ($ millions)	Three months ended March 31, 2015	2014
Cash dividends(1)	$ 47.4	$ 42.1
Capital and office expenditures	167.9	218.2
	$ 215.3	$ 260.3
Funds flow	109.2	220.5
Adjusted payout ratio (%)	197%	118%

(1) Cash dividends exclude Stock Dividend Plan proceeds in 2014.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "Senior Debt to EBITDA", "Total Debt to EBITDA", "Total Debt to Capitalization, "maximum debt to consolidated present value of total proven reserves" and "EBITDA to Interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

OVERVIEW

Our strong operational performance continued during the first quarter of 2015 as we focused on execution under a disciplined capital program. We met or exceeded all guidance targets and exited the quarter with a strong balance sheet.

Average daily production for the first quarter was 100,855 BOE/day, exceeding our guidance range of 93,000 – 100,000 BOE/day. Production was slightly lower compared to the fourth quarter of 2014 as we delayed North Dakota completions in response to low oil prices and cost uncertainties. We expect to re-establish growth in North Dakota in the second quarter as prices stabilize and costs are reduced. We continued to curtail Marcellus production during the quarter with total curtailments in line with our guidance. We are well positioned to achieve our annual average production guidance of 93,000 – 100,000 BOE/day and our crude oil and liquids guidance of 42% – 44% despite the previously announced sale of non-core crude oil assets which closed subsequent to the quarter.

First quarter funds flow decreased to $109.2 million from $220.5 million in the same period in 2014 as oil and gas sales reflected the dramatic decline in commodity prices. Our commodity hedges provided protection with cash gains of $86.8 million in the first quarter compared to losses of $15.3 million in the same period in 2014. Current quarter funds flow was reduced by $11 million as a result of a number of one-time charges including severance payments, rig termination charges and retroactive royalty adjustments. In addition, we recorded cash losses of $8.6 million on our foreign exchange collars as the Canadian dollar weakened against the U.S. dollar.

We reported a net loss of $293.2 million for the quarter compared to net income of $40.0 million in the same quarter of 2014. Our first quarter earnings benefited from commodity hedging gains of $50.4 million and one-time realized foreign exchange gains of $39.9 million as we crystalized gains on US$175 million in foreign exchange swaps. These gains were offset by asset impairment charges of $267.6 million in our U.S. cost centre as a result of the use of a 12-month trailing average commodity price to determine impairment, in accordance with U.S. GAAP.

Capital spending is on track, with $167.0 million spent in the first quarter. We continue to expect to spend $480 million in 2015 with the majority of spending weighted to the first half of the year.

General and administrative costs came in slightly under guidance of $2.40/BOE at $21.4 million or $2.36/BOE for the quarter compared to $20.5 million or $2.31/BOE in the first quarter of 2014, despite the inclusion of one-time charges for severance.

Effective in 2015 we have reclassified Marcellus gathering charges from operating expenses to transportation costs. These charges pertain to pipeline costs paid to third parties to transport saleable natural gas in the Marcellus from the lease to a downstream point of sale. This is a change in presentation and does not affect our netbacks, funds flow or net income. During the first quarter of 2015, gathering costs of $12.4 million or $1.37/BOE were reclassified from operating expenses to transportation costs. We expect annual gathering fees of approximately $1.35/BOE in 2015.

Based on the reclassification of $1.35/BOE of annual gathering costs, we are revising our 2015 guidance for operating costs downwards from $11.10/BOE to $9.75/BOE. Operating expenses came in below our revised guidance, totaling $87.7 million or $9.66/BOE compared to $79.9 million or $8.98/BOE in the first quarter of 2014. Operating costs in the first quarter were $6.1 million lower compared to the fourth quarter of 2014 as we began to see cost savings materialize. We are issuing 2015 transportation guidance of $3.00/BOE compared to previous transportation of $1.65/BOE. Transportation costs for the quarter were $26.5 million or $2.92/BOE, compared to $22.3 million or $2.51/BOE for the same period in 2014. Our aggregate guidance remains unchanged.

Despite a continued decline in commodity prices during the quarter we have maintained a strong balance sheet. At March 31, 2015, we were approximately 13% drawn on our $1.0 billion credit facility and had a debt to funds flow ratio of 1.7x and Senior Debt to Earnings before Interest, Taxes, Depreciation and Amortization and other non-cash charges ("EBITDA") ratio of 1.6x. Subsequent to the quarter, we closed non-core asset sales with combined proceeds of $185.8 million, net of closing costs, and used the proceeds to repay our outstanding debt. These divestments include the previously announced sale of our Pembina waterflood assets which closed on April 15, 2015.

RESULTS OF OPERATIONS

Production

Production for the first quarter totaled 100,855 BOE/day, exceeding our guidance range of 93,000 – 100,000 BOE/day and increasing 2% compared to 98,821 BOE/day in the first quarter of 2014. This increase was driven by growth in our Fort Berthold assets, where production increased 6% year over year due to our ongoing development program. Gas production remained relatively flat compared to the first quarter of 2014, with growth of almost 10% in our Marcellus gas production offset by the divestment of non-core Canadian natural gas properties in the second half of 2014.

Compared to production in the fourth quarter of 2014 of 105,591 BOE/day, production was down 4% primarily due to decreased crude oil and liquids production in the U.S. as we delayed North Dakota completions in response to low oil prices and cost uncertainties. Natural gas production also decreased slightly, down 3% compared to the fourth quarter. We continued to curtail our Marcellus natural gas production during the quarter in line with our guidance range.

Given the decrease in our crude oil production, our crude oil and natural gas liquids weighting decreased to 43% in the first quarter of 2015 from 44% in the fourth quarter of 2014. Our crude oil and natural gas liquids production remains in line with our guidance range of 42% – 44%.

Average daily production volumes for the three months ended March 31, 2015 and 2014 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2015**	**2014**	**% Change**
Crude oil (bbls/day)	39,355	37,760	4%
Natural gas liquids (bbls/day)	3,735	3,262	15%
Natural gas (Mcf/day)	346,589	346,794	0%
Total daily sales (BOE/day)	100,855	98,821	2%

We are maintaining our annual average production guidance for 2015 of 93,000 – 100,000 BOE/day and are well positioned to achieve both our production and liquids guidance despite the sale of non-core assets with production of approximately 1,900 BOE/day that closed subsequent to the quarter. This guidance includes our previously announced divestments but does not contemplate any additional acquisitions or divestments.

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 2015 to the first quarter of 2014:

Pricing (average for the period)	Q1 2015	Q4 2014	Q3 2014	Q2 2014	Q1 2014
Benchmarks					
WTI crude oil (US$/bbl)	$ 48.64	$ 73.15	$ 97.17	$ 102.99	$ 98.68
AECO natural gas – monthly index (CDN$/Mcf)	2.95	4.01	4.22	4.68	4.76
AECO natural gas – daily index (CDN$/Mcf)	2.75	3.60	4.02	4.69	5.71
NYMEX natural gas – last day (US$/Mcf)	2.98	4.00	4.06	4.67	4.94
US/CDN exchange rate	1.24	1.14	1.09	1.09	1.10
Enerplus selling price(1)					
Crude oil (CDN$/bbl)	$ 44.04	$ 69.17	$ 88.28	$ 96.46	$ 93.04
Natural gas liquids (CDN$/bbl)	22.48	42.34	46.76	51.80	67.90
Natural gas (CDN$/Mcf)	2.58	3.25	3.36	4.15	5.07
Average differentials					
MSW Edmonton – WTI (US$/bbl)	$ (6.80)	$ (6.36)	$ (7.93)	$ (6.13)	$ (8.25)
WCS Hardisty – WTI (US$/bbl)	(14.73)	(14.24)	(20.18)	(20.04)	(23.13)
Brent Futures (ICE) – WTI (US$/bbl)	6.58	3.85	6.26	6.75	9.19
AECO monthly – NYMEX (US$/Mcf)	(0.60)	(0.47)	(0.18)	(0.38)	(0.63)
Enerplus realized differentials(1)					
Canada crude oil – WTI (US$/bbl)	$ (15.22)	$ (12.17)	$ (20.51)	$ (16.77)	$ (20.07)
Canada natural gas – NYMEX (US$/Mcf)	(0.46)	(0.62)	(0.29)	(0.46)	(0.04)
Bakken crude oil – WTI (US$/bbl)	(11.65)	(12.15)	(12.81)	(12.81)	(9.82)
Marcellus natural gas – NYMEX (US$/Mcf)	(1.32)	(1.62)	(1.70)	(1.48)	(0.86)

(1) Before transportation costs, royalties and commodity derivative instruments.

Crude Oil and Natural Gas Liquids

WTI crude oil prices continued their decline from the previous quarter, averaging US$48.64/bbl due to global oversupply and growing inventories in the U.S., which increased by 22% from the end of 2014. Growing concerns that storage could reach maximum levels in certain regions, specifically at Cushing, Oklahoma, resulted in daily WTI prices settling at a low of US$43.46/bbl in March. WTI prices have since recovered as the threat of storage congestion in the U.S. has eased somewhat heading into the summer.

Heavy crude oil differentials in Canada weakened slightly during the quarter, with WCS averaging US$14.73/bbl below WTI, compared to US$14.24/bbl below WTI in the previous quarter. Light crude oil differentials also weakened, averaging US$6.80/bbl below WTI during the quarter, compared to US$6.36/bbl in the previous quarter. Canadian heavy oil production continued to move on rail despite higher transportation costs compared to pipelines due to existing term rail commitments made by shippers. Despite Canadian crude differentials trading wider in the quarter, the outlook ahead is positive. Improved market access, particularly to the U.S. Gulf Coast, has reduced the downside impact mid-continent refinery outages have historically had on Canadian prices. Reduced supply from oil sands producers due to seasonal maintenance is expected to further strengthen Canadian crude oil differentials in the second quarter.

In the U.S., our average realized crude oil differential was US$11.65/bbl less than WTI, an improvement of US$0.50/bbl versus the previous quarter. Strong Brent/WTI spreads improved the netback associated with oil sold to rail buyers. Increased rail capacity coming into service started to compete for production that would otherwise flow via pipeline, which caused narrowing Bakken differentials during the quarter. The reversal of Enbridge's Line 9 scheduled for the second quarter of 2015 is expected to provide support for U.S. Bakken differentials in the coming months.

Our sales price for natural gas liquids during the quarter fell by 47% compared to the fourth quarter of 2014 to average $22.48/bbl. The price received for propane decreased almost 60% versus the previous quarter due to the decline in crude oil prices as well as rapidly building inventories, with propane stocks in the U.S. almost 90% higher on average during the quarter compared to the same period last year. Additionally, the benchmark prices for butane and condensate fell by 27% and 30%, respectively, during the quarter due to the significant weakness in crude oil prices.

Natural Gas

Natural gas prices at both AECO and NYMEX were sharply lower in the quarter as strong production in the U.S. combined with a lengthy delay to winter demand in key regions in the U.S. allowed gas in storage to return to more seasonally average levels compared to this time last year. AECO monthly index prices fell by 26% versus the previous quarter to average $2.95/Mcf, while NYMEX gas prices also fell by 26% to average US$2.98/Mcf. Natural gas prices have continued to weaken throughout April as we head into a shoulder season for demand and U.S. production remains strong relative to last year.

Natural gas prices in the Marcellus also traded sharply lower in the quarter. Spot prices on the Transco Leidy pipeline averaged US$1.29/Mcf and TGP Zone 4 Marcellus daily prices averaged US$1.29/Mcf, both over 35% lower than the previous quarter. Outside of the northeast Pennsylvania producing region, prices at Dominion South Point fell by only 22% to average US$1.85/Mcf in the quarter.

With approximately 46% of our Marcellus production sold under long-term sales contracts with stronger price exposure outside of the northeast Pennsylvania producing region, our overall realized Marcellus sales price was US$1.66/Mcf. This equated to a discount to NYMEX of US$1.32/Mcf for our Marcellus production.

Foreign Exchange

During the first quarter of 2015 the Canadian dollar continued to weaken and fell 8%; the largest quarterly decline since 2008 during the credit crisis. This was due to a number of factors including the Bank of Canada's unexpected interest rate cut of 25 basis points in January, the continued decline of global oil prices, and the anticipation of increasing interest rates in the U.S. as a result of a strengthening economy. The Canadian dollar began the year at a USD/CDN exchange rate of 1.17 and weakened to 1.28 before ending the quarter at 1.27. Subsequent to the quarter end, the Canadian dollar has strengthened to 1.20 as a result of improved oil prices and a more balanced tone from the Bank of Canada. The majority of our oil and gas sales are based on U.S. dollar denominated indices and therefore a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the weaker Canadian dollar also increases our U.S. dollar denominated operating costs, capital spending and the interest on our U.S. dollar denominated senior notes.

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. As of May 5, 2015, we have swapped an average of 16,841 bbls/day of crude oil from April 1, 2015 to June 30, 2015 at an average price of US$90.40/bbl, which represents approximately 54% of our forecasted crude oil production after royalties for the same period. For the second half of 2015, we have 8,000 bbls/day of crude oil swapped at an average price of US$93.86/bbl, which represents approximately 26% of our forecasted crude oil production after royalties. In relation to these swaps, we have purchased call options to participate in price upside above US$93.00/bbl on 4,000 bbls/d, and sold put options at an average strike price of US$62.23/bbl, offsetting the cost of the call premium. If actual monthly WTI prices fall below US$62.23/bbl for individual months during the remainder of 2015, our swaps on approximately 13% of our forecasted net crude oil production are effectively converted to WTI monthly index plus US$29.87/bbl, using a weighted average swap price for the year of $92.10/bbl. Additionally, we have entered into WCS differential swap positions to manage our exposure related to Canadian crude oil differentials. Overall, we expect our crude related hedge contracts to protect a significant portion of our funds flow during 2015.

For 2016, we have downside protection on 26% of our forecasted crude oil production net of royalties, with 6,000 bbls/day protected through 3 way collars (US$50/bbl by US$65/bbl by $US80/bbl), and an additional 2,000 bbls/day swapped at $65.50/bbl.

During the quarter we added modestly to our 2015 NYMEX gas hedge program. As of May 5, 2015, we are swapped on an average of 115,600 Mcf/day at an average price of US$3.92/Mcf for the remainder of 2015, representing approximately 46% of our forecasted natural gas production after royalties. In relation to the swaps, we have purchased a call spread on 5,000 Mcf/d to participate in NYMEX price upside and sold NYMEX put options on 5,000 Mcf/day at an average price of $3.25/Mcf to offset the net cost of the call spread. We do not have any gas hedging in place for 2016.

The following is a summary of our financial contracts in place at May 5, 2015, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[(1)]			NYMEX Natural Gas (US$/Mcf)[(1)]			
	Apr 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Jan 1, 2016 – Dec 31, 2016	Apr 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Sep 30, 2015	Oct 1, 2015 – Oct 31, 2015	Nov 1, 2015 – Dec 31, 2015
Downside Protection							
Sold Swaps	$ 90.40	$ 93.86	$ 65.50	$ 3.98	$ 3.83	$ 3.85	$ 4.04
%	54%	26%	7%	43%	53%	45%	37%
Purchased Puts	–	–	$ 65.00	–	–	–	–
%	–	–	19%	–	–	–	–
Upside Participation Collars							
Sold Puts	$ 62.23	$ 62.23	$ 50.00	$ 3.25	$ 3.25	$ 3.25	$ 3.25
%	13%	13%	19%	2%	2%	2%	2%
Purchased Calls	93.00	93.00	–	$ 4.29	$ 4.29	$ 4.29	$ 4.29
%	13%	13%	–	2%	2%	2%	2%
Sold Calls	–	–	$ 80.00	$ 5.00	$ 5.00	$ 5.00	$ 5.00
%	–	–	19%	2%	2%	2%	2%

(1) Based on weighted average price (before premiums) and assumed average annual production of 93,000 – 100,000 BOE/day for 2015 and 2016, less royalties and production taxes of 21.0% in aggregate.

During 2014, we entered into foreign exchange collars to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and natural gas sales with upside participation in the event the Canadian dollar weakened. As of May 5, 2015 we have US$24 million per month hedged for 2015 at an average USD/CDN floor of 1.1088, a ceiling of 1.1845 and a conditional ceiling of 1.1263. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional ceiling is used to determine the settlement amount.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	Three months ended March 31, 2015	2014
Cash gains/(losses):		
Crude oil	$ 70.6	$ (10.7)
Natural gas	16.2	(4.6)
Total cash gains/(losses)	$ 86.8	$ (15.3)
Non-cash gains/(losses):		
Change in fair value – crude oil	$ (36.0)	$ (9.4)
Change in fair value – natural gas	(0.4)	(7.9)
Total non-cash gains/(losses)	$ (36.4)	$ (17.3)
Total gains/(losses)	$ 50.4	$ (32.6)

(Per BOE)	Three months ended March 31, 2015	2014
Total cash gains/(losses)	$ 9.56	$ (1.72)
Total non-cash gains/(losses)	(4.01)	(1.94)
Total gains/(losses)	$ 5.55	$ (3.66)

During the first quarter of 2015, we realized cash gains of $70.6 million on our crude oil contracts and $16.2 million on our natural gas contracts. In comparison, during the first quarter of 2014, we realized cash losses of $10.7 million on our crude oil contracts and $4.6 million on our natural gas contracts. The cash gains in 2015 were due to contracts which provided floor protection above market prices, while cash losses in 2014 were a result of 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 2015 the fair value of our crude oil and natural gas contracts represented net gain positions of $131.2 million and $48.8 million, respectively. The change in the fair value of our crude oil and natural gas contracts during the first quarter of 2015 represented losses of $36.0 million and $0.4 million, respectively.

During the first quarter of 2015 we recorded total cash losses of $8.6 million on our foreign exchange collars and $39.9 million in cash gains on the unwind of our US$175 million in foreign exchange swaps. Unrealized foreign exchange derivative losses of $51.8 million included $27.6 million to reverse cumulative mark-to-market gains on the foreign exchange swaps and $24.2 million of mark-to-market losses on our foreign exchange collars. At March 31, 2015, the fair value of foreign exchange derivatives was a net loss of $29.9 million. See Note 15 for further information.

Revenues

	Three months ended March 31,	
($ millions)	2015	2014
Oil and natural gas sales	$ 244.1	$ 495.0
Royalties	(39.1)	(87.3)
Oil and natural gas sales, net of royalties	$ 205.0	$ 407.7

Oil and natural gas revenues were $244.1 million in the first quarter of 2015, a decrease of 51% or $250.9 million compared to the same period in 2014. The decrease in revenue was driven by the weak commodity price environment, which saw benchmark prices decline between 40% and 50% in the first quarter of 2015 compared to the same period in 2014.

Royalties and Production Taxes

	Three months ended March 31,	
($ millions, except per BOE amounts)	2015	2014
Royalties	$ 39.1	$ 87.3
Per BOE	$ 4.31	$ 9.82
Production taxes	$ 10.8	$ 19.9
Per BOE	$ 1.19	$ 2.23
Royalties and production taxes	$ 49.9	$ 107.2
Per BOE	$ 5.50	$ 12.05
Royalties and production taxes (% of oil and natural gas sales, before transportation)	20%	22%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. During the first quarter royalties and production taxes decreased to $49.9 million from $107.2 million in the same quarter of 2014, primarily due to lower realized prices. Royalties and production taxes averaged 20% of oil and gas sales before transportation in 2015 compared to 22% for the same period in 2014.

We continue to expect an average royalty and production tax rate of 21% in 2015.

Operating Expenses and Transportation Costs

As of January 1, 2015, we have reclassified Marcellus gathering costs from operating expenses to transportation costs. These charges relate to pipeline costs paid to third parties to transport saleable natural gas from the lease to downstream points of sale. This is a presentation change with no impact on our netback, funds flow or net income. All comparative periods have been presented to conform with the current period presentation.

During the first quarter of 2015, Marcellus gathering fees were $12.4 million or $1.37/BOE compared to $9.2 million or $1.04/BOE during the same period of 2014.

Total operating expenses and transportation costs for the current quarter and comparative periods before and after the reclassification are provided below:

	2015 Guidance	Three months ended March 31, 2015		Three months ended March 31, 2014	
	Per BOE	$ millions	Per BOE	$ millions	Per BOE
Operating Expenses, before reclassification	$ 11.10	$ 100.1	$ 11.03	$ 89.1	$ 10.02
Gathering Fees	(1.35)	(12.4)	(1.37)	(9.2)	(1.04)
Operating Expenses, after reclassification	$ 9.75	$ 87.7	$ 9.66	$ 79.9	$ 8.98
Transportation Costs, before reclassification	$ 1.65(1)	$ 14.1	$ 1.55	$ 13.1	$ 1.47
Gathering Fees	1.35	12.4	1.37	9.2	1.04
Transportation Costs, after reclassification	$ 3.00	$ 26.5	$ 2.92	$ 22.3	$ 2.51

(1) Traditionally, we have not provided guidance for transportation costs (total costs of $1.52/BOE in 2014, before reclassification of gathering costs). After the reclassification of gathering costs, we are guiding to $3.00/BOE for 2015

Operating costs totaled $87.7 million or $9.66/BOE during the first quarter compared to $79.9 million or $8.98/BOE in the first quarter of 2014. The increase in operating costs was due the impact of a weak Canadian dollar on our U.S. operating costs along with higher well servicing and repairs and maintenance costs in the U.S.

Compared to the fourth quarter of 2014, operating costs decreased $6.1 million as we began to realize cost savings across our operations as a result of our ongoing cost control measures. These savings were offset somewhat by the weakening Canadian dollar.

Transportation costs totaled $26.5 million or $2.92/BOE, compared to $22.3 million or $2.51/BOE for the same period in 2014. Transportation expense increased over the prior year as a result of higher Marcellus gathering fees and an overall increase in U.S. transportation fees due to a weak Canadian dollar.

We are adjusting our 2015 guidance for operating costs from $11.10/BOE to $9.75/BOE and are issuing transportation guidance of $3.00/BOE from $1.65/BOE to take into account the reclassification of the Marcellus gathering fees of $1.35/BOE between the two categories. The aggregate guidance remains unchanged from the beginning of the year.

Netbacks

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. Certain prior period amounts have been reclassified to conform with current period presentation.

	Three months ended March 31, 2015		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	44,758 BOE/day	336,582 Mcfe/day	100,855 BOE/day
Netback(1) $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 38.99	$ 2.87	$ 26.89
Royalties and production taxes	(9.71)	(0.36)	(5.50)
Cash operating costs	(13.45)	(1.08)	(9.56)
Transportation	(1.98)	(0.60)	(2.92)
Netback before hedging	$ 13.85	$ 0.83	$ 8.91
Cash gains/(losses)	17.52	0.54	9.56
Netback after hedging	$ 31.37	$ 1.37	$ 18.47
Netback before hedging ($ millions)	$ 55.8	$ 25.1	$ 80.9
Netback after hedging ($ millions)	$ 126.4	$ 41.3	$ 167.7

Netbacks by Property Type	Three months ended March 31, 2014 Crude Oil	Natural Gas	Total
Average Daily Production	42,307 BOE/day	339,084 Mcfe/day	98,821 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 86.23	$ 5.44	$ 55.66
Royalties and production taxes	(21.64)	(0.81)	(12.05)
Cash operating costs	(12.43)	(1.06)	(8.97)
Transportation	(1.85)	(0.48)	(2.51)
Netback before hedging	$ 50.31	$ 3.09	$ 32.13
Cash gains/(losses)	(2.80)	(0.15)	(1.72)
Netback after hedging	$ 47.51	$ 2.94	$ 30.41
Netback before hedging ($ millions)	$ 191.5	$ 94.2	$ 285.7
Netback after hedging ($ millions)	$ 180.9	$ 89.5	$ 270.4

(1) See "Non-GAAP Measures" in this MD&A.

Our crude oil properties accounted for 69% of our corporate netback before hedging for the first quarter of 2015 compared to 67% for the same period in 2014. Crude oil and natural gas netbacks per BOE decreased in 2015 from the same period in 2014 as a result of a significant decline in commodity prices. The impact of lower prices was partially offset by cash hedging gains.

General and Administrative ("G&A") Expenses

Total G&A expenses include cash G&A expenses as well as share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 14 for further detail). SBC charges are dependent on our share price and can fluctuate from period to period.

($ millions)	Three months ended March 31, 2015	2014
Cash:		
G&A expense	$ 21.4	$ 20.5
Share based compensation expense	7.3	6.9
Non-Cash:		
Share based compensation expense	5.0	2.9
Equity swap loss/(gain)	(1.6)	(1.2)
Total G&A expenses	$ 32.1	$ 29.1

(Per BOE)	Three months ended March 31, 2015	2014
Cash:		
G&A expense	$ 2.36	$ 2.31
Share based compensation expense	0.80	0.77
Non-Cash:		
Share based compensation expense	0.55	0.33
Equity swap loss/(gain)	(0.18)	(0.14)
Total G&A expenses	$ 3.53	$ 3.27

Cash G&A expenses during the first quarter of 2015 were $21.4 million or $2.36/BOE, in line with guidance of $2.40/BOE and slightly higher than $20.5 million or $2.31/BOE in the first quarter of 2014. The increase in cash G&A for the first quarter was primarily due to one-time severance payments of $2.0 million.

Our share price increased by 15% during the quarter, increasing our cash and non-cash SBC to $7.3 million ($0.80/BOE) and $5.0 million ($0.55/BOE), respectively, compared to $6.9 million ($0.77/BOE) and $2.9 million ($0.33/BOE) during the same period in 2014.

We have hedged a portion of the outstanding cash settled grants under our LTI plans. As a result of the increase in our share price since year end we recorded a non-cash mark-to-market gain of $1.6 million on these hedges during the first quarter of 2015. As of March 31, 2015 we had 630,000 units hedged at a weighted average price of $15.82/share.

We continue to expect cash G&A expenses of approximately $2.40/BOE for 2015. We do not provide guidance for SBC because it is dependent on our share price and our performance relative to our peers.

Interest Expense

	Three months ended March 31,	
($ millions)	2015	2014
Interest on senior notes and bank facility	$ 16.8	$ 14.7
Non-cash interest expense	0.2	0.5
Total interest expense	$ 17.0	$ 15.2

We recorded total interest expense of $17.0 million during the first quarter of 2015 compared to $15.2 million for the same period in 2014. The increase in interest expense corresponds to an increase in higher interest rate senior notes following our September 2014 private placement of US$200 million, the proceeds of which were used to repay our short-term bank debt. Interest expense was further increased by the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments.

Non-cash amounts recorded in interest expense include amortization of deferred financing charges. See Note 11 for further details.

At March 31, 2015 approximately 90% of our debt was based on fixed interest rates and 10% on floating interest rates, with weighted average interest rates of 5.3% and 2.6%, respectively.

Foreign Exchange

	Three months ended March 31,	
($ millions)	2015	2014
Realized loss/(gain)	$ (35.6)	$ 0.1
Unrealized loss/(gain)	139.8	1.4
Total foreign exchange loss/(gain)	$ 104.2	$ 1.5

We recorded a net foreign exchange loss of $104.2 million during the first quarter of 2015 compared to $1.5 million for the same period in 2014. During the quarter, we unwound our US$175 million foreign exchange swaps with terms extending to 2021 for proceeds of $39.9 million. This gain was offset by realized losses on our foreign exchange collars and day-to-day transactions denominated in foreign currencies.

We recorded unrealized losses of $51.8 million on our foreign exchange derivatives and $88.0 million on the translation of U.S. dollar debt and working capital. See Note 12 for further details.

Capital Investment

($ millions)	Three months ended March 31, 2015	2014
Capital spending	$ 167.0	$ 217.8
Office capital	0.9	0.4
Sub-total	$ 167.9	$ 218.2
Property and land acquisitions	$ (0.2)	$ 10.0
Property divestments	(3.7)	(117.2)
Sub-total	$ (3.9)	$ (107.2)
Total	$ 164.0	$ 111.0

Capital spending for the first quarter of 2015 totaled $167.0 million compared to $217.8 million during the same period in 2014. Although spending slowed in the first quarter due to continued weakness in commodity prices, we continued to invest modestly in our core areas, with spending of $78.4 million on our Fort Berthold crude oil properties, $56.8 million on our Canadian crude properties, $19.5 million on our deep gas properties in Canada and $11.3 million on our Marcellus assets.

There were no acquisitions during the first quarter of 2015, although we recorded adjustments pertaining to prior period property acquisitions. In comparison, during the first quarter of 2014 we spent $10.0 million which included the purchase of additional undeveloped land in North Dakota and Pennsylvania.

During the first quarter of 2015, we completed several minor non-core property divestments of undeveloped land for proceeds of approximately $3.7 million. During the first quarter of 2014, property divestments totaled $117.2 million which included the sale of the balance of our Montney acreage and our overriding gas royalty interest in the Jonah property in Wyoming.

Subsequent to the quarter, we completed the sales of non-core assets for combined proceeds of $185.8 million, net of closing costs, including the previously announced sale of our Pembina waterflood assets that closed on April 15, 2015.

We continue to expect annual capital spending of $480 million, with the majority of spending weighted to the first half of 2015.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

($ millions, except per BOE amounts)	Three months ended March 31, 2015	2014
DDA&A expense	$ 132.4	$ 132.2
Per BOE	$ 14.58	$ 14.86

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2015 DDA&A was $132.4 million compared to $132.2 million for the same period in 2014.

Impairment

Under U.S. GAAP, the full cost ceiling test is performed on a country by country basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves using SEC constant prices ("Standardized Measure"). SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. The Standardized Measure is not related to Enerplus' investment criteria and is not a fair value based measurement, but rather a prescribed accounting calculation. Under U.S. GAAP impairments are not reversed in future periods.

During the first quarter of 2015, trailing 12-month averages of crude oil and natural gas prices decreased significantly and resulted in a non-cash impairment of $267.6 million (before tax) being recorded in the U.S. cost centre. No impairment was recorded to the Canadian cost centre. Enerplus did not record any ceiling test impairments on its oil and natural gas properties in 2014. If commodity prices remain at levels experienced during the first quarter of 2015, the trailing twelve month prices used in the ceiling calculation will decline further and may lead to additional write downs of our oil and natural gas properties. See Note 5 for trailing 12-month prices used and further information.

Asset Retirement Obligation

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are estimated by Enerplus based on our net ownership interest, anticipated costs to abandon and reclaim and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $295.2 million at March 31, 2015 compared to $288.7 million at December 31, 2014. See Note 8 for further information. Asset retirement obligation settlements for the first quarter totaled $3.9 million compared to $19.4 million for the same period in 2014.

Income Taxes

	Three months ended March 31,	
($ millions)	2015	2014
Current tax expense	$ 0.1	$ 7.7
Deferred tax expense/(recovery)	(138.4)	24.5
Total tax expense/(recovery)	$ (138.3)	$ 32.2

We recorded a total tax recovery of $138.3 million for the three months ended March 31, 2015 compared to a $32.2 million expense for the same period in 2014. The decrease in total tax expense is due primarily to lower income in 2015 which included a $267.6 million non-cash asset impairment expense recorded in the U.S. cost centre during the quarter.

Given the decrease in commodity prices and U.S. forecasted net income for the year, we expect current tax of less than 1% of our U.S. funds flow in 2015. As a result, our current tax expense has decreased to $0.1 million for the three months ended March 31, 2015 from $7.7 million for the same period in 2014. Our U.S. current tax is comprised mainly of Alternative Minimum Tax (“AMT”) payable with respect to our U.S. subsidiary. We expect to recover any AMT paid in future years as an offset to regular U.S. income taxes otherwise payable. We do not expect to pay any cash taxes in Canada in 2015. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisitions and divestment activity. See Note 13 for further information.

SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2015			Three months ended March 31, 2014		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	16,973	22,382	39,355	16,577	21,183	37,760
Natural gas liquids (bbls/day)	2,359	1,376	3,735	2,540	722	3,262
Natural gas (Mcf/day)	135,419	211,170	346,589	151,627	195,167	346,794
Total average daily production (BOE/day)	41,902	58,953	100,855	44,388	54,433	98,821
Pricing[2]						
Crude oil (per bbl)	$ 41.47	$ 45.99	$ 44.04	$ 86.74	$ 97.97	$ 93.04
Natural gas liquids (per bbl)	29.14	11.06	22.48	69.46	62.38	67.90
Natural gas (per Mcf)	3.13	2.22	2.58	5.41	4.81	5.07
Capital Expenditures						
Capital spending	$ 76.9	$ 90.1	$ 167.0	$ 127.7	$ 90.1	$ 217.8
Acquisitions	1.2	(1.4)	(0.2)	–	10.0	10.0
Divestments	(1.0)	(2.7)	(3.7)	(67.7)	(49.5)	(117.2)
Netback Before Hedging						
Oil and natural gas sales	$ 107.9	$ 136.2	$ 244.1	$ 220.0	$ 275.0	$ 495.0
Royalties	(12.4)	(26.7)	(39.1)	(34.0)	(53.3)	(87.3)
Production taxes	(1.8)	(9.0)	(10.8)	(2.0)	(17.9)	(19.9)
Cash operating expense	(57.0)	(29.8)	(86.8)	(62.1)	(17.7)	(79.8)
Transportation expense	(6.2)	(20.3)	(26.5)	(5.9)	(16.4)	(22.3)
Netback before hedging	$ 30.5	$ 50.4	$ 80.9	$ 116.0	$ 169.7	$ 285.7
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (50.4)	$ –	$ (50.4)	$ 32.6	$ –	$ 32.6
General and administrative expense[3]	23.5	8.6	32.1	23.3	5.8	29.1
Current income tax expense/(recovery)	–	0.1	0.1	(0.2)	7.9	7.7

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) Includes share based compensation.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2015				
First Quarter	$ 205.0	$ (293.2)	$ (1.42)	$ (1.42)
2014				
Fourth Quarter	$ 325.3	$ 151.7	$ 0.74	$ 0.73
Third Quarter	378.3	67.4	0.33	0.32
Second Quarter	414.9	40.0	0.20	0.19
First Quarter	407.7	40.0	0.20	0.19
Total 2014	$ 1,526.2	$ 299.1	$ 1.46	$ 1.44
2013				
Fourth Quarter	$ 332.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	365.4	(3.7)	(0.02)	(0.02)
Second Quarter	341.3	38.5	0.19	0.19
First Quarter	313.4	(16.4)	(0.08)	(0.08)
Total 2013	$ 1,352.5	$ 48.0	$ 0.24	$ 0.24

Oil and gas sales decreased in the first quarter of 2015 due to lower realized commodity prices and a decrease in crude oil production compared to the fourth quarter of 2014. From the first quarter of 2013, oil and gas sales increased steadily until the third quarter of 2014 when realized commodity prices began to decline significantly. Net income in the first quarter of 2015 was impacted by asset impairments related to the decrease in crude oil prices and by the significant fluctuation in the U.S. dollar relative to the Canadian dollar.

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a senior debt to EBITDA threshold of 3.5x for a period of up to six months, after which it drops to 3.0x. At March 31, 2015 our senior debt to EBITDA ratio was 1.6x and our debt to funds flow ratio was 1.7x. Debt to funds flow is often used by investors and analysts to evaluate our liquidity, however, this measure is not used by Enerplus to determine compliance with financial covenants.

Total debt net of cash at March 31, 2015 was $1,272.2 million compared to $1,134.9 million at December 31, 2014. Total debt was comprised of $125.7 million of bank indebtedness and $1,149.1 million of senior notes less $2.6 million in cash. At March 31, 2015 we were approximately 13% drawn on our $1.0 billion senior, unsecured bank facility. Subsequent to quarter end, we closed non-core asset sales for proceeds of $185.8 million, net of closing costs, and used the proceeds to repay the drawn balance on our credit facility. The maturities on our senior notes range between 2015 and 2026, with approximately $100 million of scheduled principal repayments during 2015 and none in 2016.

Our working capital deficiency, excluding cash and current deferred financial and tax balances, increased to $290.6 million at March 31, 2015 from $260.5 million at December 31, 2014. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by funds flow, was 197% for the first quarter of 2015 compared to 118% for the same period in 2014. Despite the increase in our adjusted payout ratio we have continued to maintain our financial flexibility through an ongoing focus on cost efficiencies and the success of our non-core asset divestment program. As previously announced, in order to maintain our balance sheet strength we have reduced our monthly dividend by 44% from $0.09/share to $0.05/share effective with our March 2015 dividend, paid in April. We have also decreased our capital spending by 40% compared to 2014 levels, deferring spending and preserving opportunities.

We have a $1.0 billion senior, unsecured, covenant-based bank credit facility that matures on October 31, 2017. Drawn and undrawn fees range between 150 and 315 basis points over Bankers' Acceptance rates, with current drawn fees of 170 basis points. The bank credit facility ranks equally with our senior, unsecured, covenant-based notes. At March 31, 2015 we were in compliance with all covenants under our bank credit facility and outstanding 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.

The following table lists our financial covenants as at March 31, 2015:

Covenant Description		March 31, 2015
Bank Credit Facility:	**Maximum Ratio**	
Senior Debt to EBITDA	3.5 x	1.6 x
Total Debt to EBITDA	4.0 x	1.6 x
Total Debt to Capitalization(1)	50%	29%
Senior Notes:	**Maximum Ratio**	
Senior Debt to EBITDA(2)	3.0 x – 3.5 x	1.6x
Maximum debt to consolidated present value of total proven reserves	60%	42%
	Minimum Ratio	
EBITDA to Interest	4.0 x	12.9 x

Definitions

"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.

"EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion and non-cash gains and losses. EBITDA is calculated on a trailing twelve month basis and is adjusted for material acquisitions and divestments. EBITDA for the three months and the trailing twelve months ended March 31, 2015 were $165.9 million and $827.9 million, respectively.

"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.

"Capitalization" is calculated as the sum of total debt and shareholders' equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes

(1) Upon completion of a material acquisition, the Total Debt to Capitalization maximum ratio may increase to 55% for a period extending to and including the second full fiscal quarter after the completion of the acquisition
(2) Senior debt to EBITDA maximum ratio for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x

Dividends

($ millions, except per share amounts)	Three months ended March 31, 2015	2014
Cash dividends	$ 47.4	$ 42.1
Stock Dividend Plan	–	12.8
Total dividends to shareholders	$ 47.4	$ 54.9
Per weighted average share (Basic)	$ 0.23	$ 0.27

We reported a total of $47.4 million or $0.23 per share in dividends to our shareholders in the first quarter of 2015 compared to $54.9 million or $0.27 per share in the first quarter of 2014.

Effective with the April 2015 payment, we reduced the monthly dividend by 44% from $0.09 per share to $0.05 per share to preserve our balance sheet strength in both the near and long term. The dividend is an important part of our strategy to create shareholder value and we will continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Three months ended March 31,	
	2015	**2014**
Share capital ($ millions)	$ 3,125.9	$ 3,081.8
Common shares outstanding (thousands)	206,179	203,839
Weighted average shares outstanding – basic (thousands)	205,845	203,178
Weighted average shares outstanding – diluted (thousands)	205,845	205,878

During the first quarter of 2015 a total of 447,000 shares and $5.7 million of additional equity was issued pursuant to the stock option plan and the treasury settled Restricted Share Unit plan. In comparison, during the first quarter of 2014 a total of 1,081,000 shares and $18.9 million of additional equity was issued pursuant to the stock option plan and the currently inactive stock dividend plan. For further details see Note 14.

At March 31, 2015 we had 206,179,000 shares outstanding (2014 – 203,839,000) and at May 7, 2015 we had 206,224,000 shares outstanding.

2015 GUIDANCE

A summary of our 2015 guidance is below. This guidance does not include any unannounced acquisitions or divestments.

There have been no changes to our guidance this quarter, with the exception of a reclassification between operating expenses and transportation costs. This reclassification does not impact our netback, funds flow or net income.

Summary of 2015 Expectations	Target
Average annual production	93,000 – 100,000 BOE/day
Capital spending	$480 million
Production mix (volumes)	42% – 44% crude oil and liquids
Average royalty and production tax rate (% of gross sales, before transportation)	21%
Operating costs	$9.75/BOE (from $11.10/BOE, revised for Marcellus gathering cost reclassification)
Transportation costs	$3.00/BOE (revised for Marcellus gathering cost reclassification)
Cash G&A expenses	$2.40/BOE
U.S. Cash taxes (% of U.S. funds flow)	< 1%

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, 2015, 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, 2015 and ended March 31, 2015 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 2015 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our funds flow; the proportion and average production volumes associated with curtailments in the Marcellus; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity and foreign exchange risk management programs in 2015 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A, share based compensation and financing expenses; operating and transportation costs; capital spending levels in 2015 and its impact on our production level; potential future asset impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and 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; our future acquisitions and dispositions; and the amount of future cash dividends that we may pay to our shareholders.

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; that lack of adequate infrastructure will not result in further curtailment of production and/or reduced realized prices; current commodity price and cost assumptions; 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; 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 continued availability and sufficiency of our funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. In addition, our 2015 guidance contained in this MD&A is based on the following: a WTI price of US$55/bbl, a NYMEX price of US$2.75/Mcf, an AECO price of $2.50/GJ and a USD/CDN exchange rate of 1.25.

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, including further decline of, commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; 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; 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 Annual MD&A and in our other public filings).