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

The following discussion and analysis of financial results is dated May 5, 2017 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, 2017 and 2016 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2016 and 2015 and for the years ended December 31, 2016, 2015 and 2014; and
- our MD&A for the year ended December 31, 2016 (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" at the end of the MD&A 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.

OVERVIEW

Average daily production for the first quarter was 84,937 BOE/day, in line with our annual average production guidance range of 81,000 – 85,000 BOE/day. Production decreased 5% or 4,023 BOE/day from the fourth quarter of 2016 largely due to lower crude oil and liquids volumes following the December 30, 2016 sale of our non-operated North Dakota properties with production of approximately 5,000 BOE/day. The decrease in crude oil and liquids volume was offset by higher natural gas production from the Marcellus due to improved realized pricing. We are maintaining our annual average production guidance of 81,000 – 85,000 BOE/day, including approximately 38,500 – 41,500 bbls/day of crude oil and natural gas liquids. We continue to expect our average daily production and crude oil and liquids weighting to increase in the second half of the year as a result of significant capital spending in North Dakota, with expected fourth quarter average daily production of 86,000 – 91,000 BOE/day, including 43,000 – 48,000 bbls/day of crude oil and natural gas liquids.

Our capital spending for the first quarter was $120.4 million, in line with our expectation. Approximately 70% of spending directed to our North Dakota crude oil properties and 21% directed to our Canadian crude oil assets. We are maintaining our 2017 annual capital spending guidance of $450 million.

Operating expenses for the first quarter came in below annual guidance of $7.25/BOE, totaling $50.3 million or $6.59/BOE. The decrease in operating costs was mainly due to additional savings related to our previously announced Canadian non-core asset divestments, as well as lower than expected activity levels. As a result, we are reducing our annual guidance for operating expenses to $6.85/BOE from $7.25/BOE. Cash G&A expenses for the first quarter were $14.3 million or $1.87/BOE compared to annual guidance of $1.85/BOE. We are maintaining our cash G&A guidance of $1.85/BOE.

Our commodity hedging program continued to provide funds flow protection, contributing cash gains of $6.6 million in the first quarter. Since the prior quarter, we have added to our commodity hedge positions. As of May 4, 2017, we have approximately 69% of our forecasted crude oil production, net of royalties, hedged in 2017, and approximately 46% and 15% of our crude oil production, net of royalties, hedged in 2018 and 2019, respectively, based on 2017 forecasted production. We have also hedged approximately 25% of our forecasted natural gas production, net of royalties, in 2017. At March 31, 2017, the fair value of our crude oil and natural gas hedging contracts were in a net asset position of $12.7 million (December 31, 2016 - net liability of $38.3 million).

We recorded net income of $76.3 million and adjusted funds flow of $119.9 million in the first quarter, compared to $840.3 million and $107.7 million, respectively, in the fourth quarter of 2016. Both net income and adjusted funds flow benefited from improved pricing which offset the impact of reduced volumes, as well as an $8.8 million or 15% reduction in cash operating expenses.

At March 31, 2017, our total debt net of cash and restricted cash was $350.4 million and our net debt to adjusted funds flow ratio was 0.9x.

Subsequent to the first quarter, we closed the final portion of our previously announced Canadian divestment for proceeds of $60.8 million, after closing adjustments. Including the portion of the deal which closed in March 2017, the divested properties include the majority of our shallow gas assets as well as our Brooks waterflood property. These properties had combined production of approximately 7,300 BOE/day and accounted for $64.6 million of our future asset retirement obligation.

RESULTS OF OPERATIONS

Production

Average daily production for the first quarter totaled 84,937 BOE/day, in line with our annual average guidance range of 81,000 – 85,000 BOE/day. Compared to production in the fourth quarter of 2016 of 88,960 BOE/day, production decreased by 5% or 4,023 BOE/day. Crude oil and liquids production decreased by 5,200 BOE/day primarily due to the December 30, 2016 sale of our non-operated North Dakota properties with production of approximately 5,000 BOE/day (90% crude oil and liquids). Natural gas production increased 2% over the same period primarily due to higher production in the Marcellus as a result of improved realized prices.

Production in the first quarter of 2017 decreased by 13% from production levels of 97,860 BOE/day during the same period of the prior year primarily due to the sale of non-core properties throughout 2016 with production of approximately 13,500 BOE/day. With the exception of the North Dakota non-operated sale, divested volumes related to Canadian non-core assets (86% natural gas). Production levels compared to the prior period were also impacted by reduced capital spending throughout 2016.

Our crude oil and natural gas liquids production weighting decreased to 43% in the first quarter of 2017 compared to 46% in the same period of 2016 primarily due to the North Dakota non-operated divestment.

Average daily production volumes for the three months ended March 31, 2017 and 2016 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2017**	**2016**	**% Change**
Crude oil (bbls/day)	33,178	39,508	(16%)
Natural gas liquids (bbls/day)	3,158	5,494	(43%)
Natural gas (Mcf/day)	291,607	317,150	(8%)
Total daily sales (BOE/day)	84,937	97,860	(13%)

We are maintaining our annual average production guidance of 81,000 – 85,000 BOE/day and our crude oil and natural gas liquids guidance of 38,500 – 41,500 bbls/day. This guidance includes the impact of our recently announced divestment of shallow gas assets and our Brooks waterflood property with production of approximately 7,300 BOE/day. We continue to expect our average daily production and crude oil and liquids weighting to increase in the second half of the year as a result of significant capital spending in North Dakota, with fourth quarter average daily production expected to be between 86,000 – 91,000 BOE/day, including 43,000 – 48,000 bbls/day of crude oil and natural gas liquids.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, adjusted funds flow and financial condition. The following table compares quarterly average prices from the first quarter of 2017 to the previous four quarters:

Pricing (average for the period)	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Benchmarks					
WTI crude oil (US$/bbl)	$ 51.92	$ 49.29	$ 44.94	$ 45.59	$ 33.45
AECO natural gas – monthly index ($/Mcf)	2.94	2.81	2.20	1.25	2.11
AECO natural gas – daily index ($/Mcf)	2.69	3.09	2.32	1.40	1.83
NYMEX natural gas – last day (US$/Mcf)	3.32	2.98	2.81	1.95	2.09
USD/CDN average exchange rate	1.32	1.33	1.31	1.29	1.37
USD/CDN period end exchange rate	1.33	1.34	1.31	1.30	1.30
Enerplus selling price(1)					
Crude oil ($/bbl)	$ 57.53	$ 53.91	$ 47.93	$ 46.48	$ 31.59
Natural gas liquids ($/bbl)	37.76	21.31	13.85	15.67	11.34
Natural gas ($/Mcf)	3.63	2.89	2.12	1.49	1.77
Average differentials					
MSW Edmonton – WTI (US$/bbl)	$ (3.54)	$ (3.11)	$ (2.96)	$ (3.09)	$ (3.69)
WCS Hardisty – WTI (US$/bbl)	(14.58)	(14.32)	(13.50)	(13.30)	(14.24)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.63)	(1.58)	(1.35)	(0.70)	(0.99)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.70)	(1.64)	(1.40)	(0.73)	(1.07)
AECO monthly – NYMEX (US$/Mcf)	(1.10)	(0.86)	(1.13)	(0.99)	(0.56)
Enerplus realized differentials (1)					
Canada crude oil – WTI (US$/bbl)	$ (12.76)	$ (12.97)	$ (12.06)	$ (12.01)	$ (14.14)
Canada natural gas – NYMEX (US$/Mcf)	(0.56)	(0.63)	(0.92)	(0.86)	(0.63)
Bakken crude oil – WTI (US$/bbl)	(5.59)	(6.80)	(6.39)	(8.23)	(8.38)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.60)	(0.88)	(1.19)	(0.76)	(0.91)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Our average realized crude oil price during the quarter increased by 7% to $57.53/bbl, compared to a 5% increase in benchmark WTI prices. This increase was led mostly by stronger Bakken price differentials which improved by 18% during the quarter to average US$5.59/bbl below WTI. Bakken prices have continued to strengthen over the past year due to regional production declines, strong regional demand and the anticipated start-up of the Dakota Access Pipeline project in the second quarter of 2017. This project will result in regional pipeline capacity exceeding current production levels and should support stronger Bakken prices going forward. We continue to expect our Bakken crude oil differential to average US$4.50/bbl below WTI for all of 2017.

Our realized price differential for our Canadian crude oil production improved by 2% during the quarter compared to the previous quarter, due largely to our acquisition of a Canadian light crude oil waterflood property during November 2016.

Our realized price for natural gas liquids averaged $37.76/bbl during the quarter, an improvement of 77% compared to the fourth quarter of 2016, due to improvements in the underlying benchmark pricing as the supply-demand balance for natural gas liquids has improved.

NATURAL GAS

Our realized natural gas price during the first quarter improved by 26% compared to the fourth quarter of 2016 to average $3.63/Mcf. Benchmark NYMEX natural gas prices improved by 11% during the quarter, due to lower U.S. production and weather related demand increases in key regions of the U.S. through the latter part of the quarter.

Our realized Marcellus sales price differential excluding transportation and gathering improved by 32% during the quarter to average US$0.60/Mcf below NYMEX. Benchmark monthly Transco Leidy prices averaged US$0.63/Mcf below NYMEX during the first quarter. Continued growth in regional natural gas power plant demand and the steady addition of new pipeline projects in 2016 has resulted in demand exceeding supply in Northeast Pennsylvania. Our view remains that the Marcellus currently has excess pipeline capacity, and given the amount of additional infrastructure expected to be brought online over the next few years, we expect Marcellus price differentials to continue to strengthen into 2018. We now expect our Marcellus natural gas realized price differential to average US$0.60/Mcf below NYMEX during 2017.

Most of our Canadian gas production is sold under multi-year fixed AECO basis differential contracts at prices better than those currently realized in the spot market. Our realized Canadian gas price differential averaged US$0.56/Mcf below NYMEX compared to the AECO benchmark monthly price that averaged US$1.10/Mcf below NYMEX in the first quarter.

FOREIGN EXCHANGE

The USD/CDN exchange rate was 1.33 USD/CDN at March 31, 2017, and averaged 1.32 USD/CDN during the first quarter of 2017 compared to 1.33 USD/CDN during the fourth quarter of 2016. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices, and a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the fluctuations in the Canadian dollar also impact our U.S. dollar denominated costs, capital spending and the reported value of our U.S. dollar denominated debt.

Price Risk Management

We have a price risk management program that considers our overall financial position and the economics of our capital expenditures.

As of May 4, 2017, we have hedged approximately 18,680 bbls/day of our crude oil production for the remainder of 2017, which represents approximately 69% of our forecasted crude oil production, after royalties. For 2018, we have hedged 12,500 bbls/day, which represents approximately 46% of our 2017 forecasted crude oil production, after royalties. For 2019, we have hedged 4,000 bbls/day, which represents approximately 15% of our 2017 forecasted crude oil production, after royalties. Our crude oil hedges are predominantly three way collars, which consist of a sold put, a purchased put and a sold call. When WTI prices settle below the sold put strike price over the contract term, the three way collars provide a limited amount of protection above the WTI settled price equal to the difference between the strike price of the purchased and sold puts. Overall, we expect our crude oil related hedging contracts to protect a significant portion of our adjusted funds flow.

As of May 4, 2017, we have hedged approximately 50,000 Mcf/day of our natural gas production for the remainder of 2017 using NYMEX three way collars. This represents approximately 25% of our forecasted natural gas production, after royalties. When NYMEX prices settle below the sold put strike price over the contract term, the three way collars provide a limited amount of protection above the NYMEX index prices equal to the difference between the strike price of the purchased and sold puts.

The following is a summary of our financial contracts in place at May 4, 2017, expressed as a percentage of our 2017 net production volumes:

	WTI Crude Oil (US$/bbl)(1)					NYMEX Natural Gas (US$/Mcf)(1)
	Apr 1, 2017 – Jun 30, 2017	Jul 1, 2017 – Dec 31, 2017	Jan 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Apr 1, 2017 – Dec 31, 2017
Swaps						
Sold Swaps	$ 53.50	$ 53.50	$ 53.73	$ 53.73	—	—
%	7%	7%	11%	11%	—	—
Three Way Collars						
Sold Puts	$ 38.94	$ 39.62	$ 43.13	$ 45.00	$ 43.75	$ 2.06
%	52%	67%	35%	4%	15%	25%
Purchased Puts	$ 50.29	$ 50.61	$ 54.00	$ 56.00	$ 54.69	$ 2.75
%	52%	67%	35%	4%	15%	25%
Sold Calls	$ 61.14	$ 60.33	$ 63.09	$ 70.00	$ 66.18	$ 3.41
%	52%	67%	35%	4%	15%	25%

(1) Based on weighted average price (before premiums) assuming average annual production of 83,000 BOE/day less royalties and production taxes of 24%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended March 31,**	
($ millions)	**2017**	**2016**
Cash gains/(losses):		
Crude oil	$ (1.0)	$ 36.6
Natural gas	7.6	3.0
Total cash gains/(losses)	$ 6.6	$ 39.6
Non-cash gains/(losses):		
Crude oil	$ 44.4	$ (31.2)
Natural gas	6.6	5.1
Total non-cash gains/(losses)	$ 51.0	$ (26.1)
Total gains/(losses)	$ 57.6	$ 13.5

	Three months ended March 31,	
(Per BOE)	**2017**	**2016**
Total cash gains/(losses)	$ 0.86	$ 4.45
Total non-cash gains/(losses)	6.67	(2.94)
Total gains/(losses)	$ 7.53	$ 1.51

During the first quarter of 2017 we realized cash losses of $1.0 million on our crude oil contracts and cash gains of $7.6 million on our natural gas contracts. In comparison, during the first quarter of 2016 we realized cash gains of $36.6 million on our crude oil contracts and $3.0 million on our natural gas contracts. Cash gains recorded in the quarter on our natural gas contracts included a gain of $8.5 million on the unwind of a portion of our AECO-NYMEX basis physical contracts in conjunction with the sale of our Canadian non-core natural gas properties. Cash losses on crude oil contracts were primarily due to premiums paid on our three way collars.

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 2017, the fair value of our crude oil contracts was in a net asset position of $15.5 million, while the fair value of our natural gas contracts was in a net liability position of $2.8 million. For the three months ended March 31, 2017, the change in the fair value of our crude oil and natural gas contracts represented gains of $44.4 million and $6.6 million, respectively.

Revenues

	Three months ended March 31,	
($ millions)	**2017**	**2016**
Oil and natural gas sales	$ 277.7	$ 170.5
Royalties	(49.9)	(27.8)
Oil and natural gas sales, net of royalties	$ 227.8	$ 142.7

Oil and natural gas sales for the three months ended March 31, 2017 were $277.7 million, an increase of 63% from the same period in 2016. The increase in revenue during the first quarter was primarily a result of higher commodity pricing compared to the same period in 2016, which more than offset the impact of lower production.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended March 31, 2017	2016
Royalties	$ 49.9	$ 27.8
Per BOE	$ 6.53	$ 3.12
Production taxes	$ 10.4	$ 7.4
Per BOE	$ 1.36	$ 0.83
Royalties and production taxes	$ 60.3	$ 35.2
Per BOE	$ 7.89	$ 3.95
Royalties and production taxes (% of oil and natural gas sales)	22%	21%

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. A large percentage of our production is from U.S. properties where royalty rates are generally less sensitive to commodity price levels. During the three months ended March 31, 2017, royalties and production taxes increased to $60.3 million, from $35.2 million for the same period in 2016 primarily due to higher commodity prices. Royalties and production taxes averaged 22% of oil and natural gas sales before transportation costs in the first quarter of 2017 compared to 21% for the same period in 2016 due to a greater portion of our production coming from our U.S. properties with higher overall royalty rates. Alberta's Modernized Royalty Framework, which came into effect on January 1, 2017, has not had a significant impact on our Canadian royalties.

We are maintaining our average royalty and production tax rate guidance of 24% in 2017. We continue to expect our royalty rate to increase in the latter half of the year as a result of a higher U.S. production weighting.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended March 31, 2017	2016
Cash operating expenses	$ 50.3	$ 72.3
Non-cash (gains)/losses[1]	0.1	0.3
Total operating expenses	$ 50.4	$ 72.6
Per BOE	$ 6.59	$ 8.15

(1) Non-cash (gains)/losses on fixed price electricity swaps.

Operating expenses for the first quarter of 2017 totaled $50.4 million or $6.59/BOE, below our annual guidance of $7.25/BOE. Operating costs decreased by 31% from $72.6 million or $8.15/BOE during the same period of the prior year due to the divestment of higher operating cost Canadian properties throughout 2016, along with lower repairs and maintenance, fluid handling and gas facility charges compared to the prior period.

During the first quarter of 2017, we realized additional savings from our previously announced non-core divestments and cost reductions due to lower than expected activity levels. As a result, we are lowering our 2017 guidance for operating expenses to $6.85/BOE from $7.25/BOE. Although our operating costs were below guidance during the first quarter, we expect costs to increase on a per BOE basis during the second half of the year with our higher liquids weighting and scheduled turnarounds in Canada.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended March 31, 2017	2016
Transportation costs	$ 29.6	$ 25.7
Per BOE	$ 3.88	$ 2.89

For the three months ended March 31, 2017, transportation costs were $29.6 million or $3.88/BOE, below our annual guidance of $4.00/BOE. Transportation costs have increased by $3.9 million from $25.7 million or $2.89/BOE during the same period in 2016. The increase in the cost per BOE is primarily due to additional firm transportation commitments, including 30,000 Mcf/day of additional interstate pipeline capacity from the Marcellus region to downstream connections that came into effect in August 2016.

We are maintaining our 2017 guidance for transportation costs of $4.00/BOE, as our growing U.S. production volumes have higher associated transportation costs.

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.

	Three months ended March 31, 2017		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	40,393 BOE/day	267,264 Mcfe/day	84,937 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 49.14	$ 4.12	$ 36.33
Royalties and production taxes	(12.58)	(0.60)	(7.89)
Cash operating expenses	(10.26)	(0.54)	(6.57)
Transportation costs	(2.50)	(0.85)	(3.88)
Netback before hedging	$ 23.80	$ 2.13	$ 17.99
Cash gains/(losses)	(0.26)	0.31	0.86
Netback after hedging	$ 23.54	$ 2.44	$ 18.85
Netback before hedging ($ millions)	$ 86.4	$ 51.1	$ 137.5
Netback after hedging ($ millions)	$ 85.5	$ 58.6	$ 144.1

	Three months ended March 31, 2016		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	48,280 BOE/day	297,480 Mcfe/day	97,860 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 27.54	$ 1.83	$ 19.14
Royalties and production taxes	(6.43)	(0.26)	(3.95)
Cash operating expenses	(10.17)	(1.02)	(8.12)
Transportation costs	(1.87)	(0.65)	(2.89)
Netback before hedging	$ 9.07	$ (0.10)	$ 4.18
Cash gains/(losses)	8.32	0.11	4.45
Netback after hedging	$ 17.39	$ 0.01	$ 8.63
Netback before hedging ($ millions)	$ 39.9	$ (2.6)	$ 37.3
Netback after hedging ($ millions)	$ 76.5	$ 0.4	$ 76.9

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

Crude oil and natural gas netbacks per BOE after hedging were higher for the three months ended March 31, 2017 compared to the same period in 2016 primarily due to significantly higher oil and natural gas sales as a result of improvements in commodity prices and differentials in North Dakota and Marcellus regions, along with reductions to our operating expenses. In 2017, our crude oil properties accounted for 63% of our netback before hedging compared to 100% of our netback during the first quarter of 2016.

General and Administrative ("G&A") Expenses

Total G&A expenses include cash G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans"). See Note 10 and Note 13 to the Interim Financial Statements for further details.

	Three months ended March 31,	
($ millions)	2017	2016
Cash:		
G&A expense	$ 14.3	$ 18.4
Share-based compensation expense	0.2	0.7
Non-Cash:		
Share-based compensation expense	8.1	3.4
Equity swap loss/(gain)	0.9	(0.1)
Total G&A expenses	$ 23.5	$ 22.4

	Three months ended March 31,	
(Per BOE)	2017	2016
Cash:		
G&A expense	$ 1.87	$ 2.07
Share-based compensation expense	0.02	0.08
Non-Cash:		
Share-based compensation expense	1.06	0.39
Equity swap loss/(gain)	0.12	(0.02)
Total G&A expenses	$ 3.07	$ 2.52

For the three months ended March 31, 2017, cash G&A expenses were $14.3 million or $1.87/BOE, in line with our annual guidance of $1.85/BOE. The decrease in cash G&A expenses from $18.4 million or $2.07/BOE in the same period in 2016 was primarily due to continued cost savings initiatives and the impact of reductions in staff levels throughout 2016 as we continue to divest of non-core properties and focus our business.

During the quarter, we reported cash SBC expense of $0.2 million or $0.02/BOE, a decrease of 71% compared to $0.7 million or $0.08/BOE during the same period in 2016. During the first quarter of 2016, we recorded expenses related to our Director Share Unit ("DSU") plan and the final settlement of our cash-settled Restricted Share Unit ("RSU") plan, while the current quarter expense relates solely to the annual grant of our DSU plan offset by the impact of a lower share price on outstanding units. Our DSU plan is the only remaining LTI plan that we intend to settle in cash. We recorded non-cash SBC of $8.1 million or $1.06/BOE in the first quarter of 2017 compared to $3.4 million or $0.39/BOE during the same period in 2016. The increase in non-cash SBC was a result of an improvement in our performance multiplier based on our relative return in the Toronto Stock Exchange Oil and Gas Producers Index.

We have hedges in place on the outstanding cash-settled grants under our LTI plans. In the first quarter we recorded a non-cash mark-to-market loss of $0.9 million on these hedges. As of March 31, 2017 we had 470,000 units hedged at a weighted average price of $16.89 per share.

We are maintaining our cash G&A guidance of $1.85/BOE.

Interest Expense

For the three months ended March 31, 2017, we recorded total interest expense of $10.1 million, compared to $14.5 million for the same period in 2016. The decrease in interest expense corresponds to a decrease in the aggregate principal amount of our outstanding senior notes following our repurchase of US$267 million of senior notes during the first half of 2016, along with a decrease in our drawn bank credit facility compared to the same period in 2016.

At March 31, 2017, we were essentially undrawn on our $800 million bank credit facility, and our debt balance consisted primarily of fixed interest rate senior notes with a weighted average interest rate of 5.0%. See Note 7 in the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended March 31, 2017	2016
Realized loss/(gain)	$ 0.1	$ 1.8
Unrealized loss/(gain)	(3.9)	(56.2)
Total foreign exchange loss/(gain)	$ (3.8)	$ (54.4)
USD/CDN average exchange rate	1.32	1.37
USD/CDN period end exchange rate	1.33	1.30

For the three months ended March 31, 2017, we recorded a net foreign exchange gain of $3.8 million, compared to a gain of $54.4 million for the same period in 2016. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies, while unrealized gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing March 31, 2017 to December 31, 2016, the Canadian dollar strengthened relative to the U.S. dollar resulting in unrealized gains of $3.9 million. See Note 11 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended March 31, 2017	2016
Capital spending	$ 120.4	$ 43.3
Office capital	0.1	—
Sub-total	120.5	43.3
Property and land acquisitions	$ 2.5	$ 3.6
Property divestments	0.9	(187.8)
Sub-total	3.4	(184.2)
Total	$ 123.9	$ (140.9)

Capital spending for the three months ended March 31, 2017, totaled $120.4 million, compared to $43.3 million for the same period in 2016. The increase is in line with our strategy to re-initiate growth through an increased capital program in 2017. During the first quarter we spent $85.1 million on our North Dakota crude oil properties, $25.1 million on our Canadian crude oil properties and $9.8 million on our Marcellus natural gas assets.

During the first quarter, we completed a portion of our previously announced Canadian asset divestments. Although we recorded nominal proceeds on the divestment, which had associated natural gas production of 1,700 BOE/day, it resulted in a $25.1 million decrease in our asset retirement obligation. This divestment was offset by adjustments pertaining to prior period divestments. In comparison, during the same period of 2016 we disposed of several properties including certain Canadian Deep Basin properties located in Alberta for proceeds of $187.8 million with production of 5,400 BOE/day.

Subsequent to the first quarter, we closed the remaining 5,600 BOE/day of our previously announced divestments of various non-core Canadian properties. This included the remainder of our shallow gas assets and our Brooks waterflood property, for aggregate proceeds of $60.8 million, after closing adjustments.

We continue to expect 2017 annual capital spending of $450 million.

Gain on Asset Sales and Note Repurchases

Under full cost accounting rules, divestments of oil and natural gas properties are generally accounted for as adjustments to the full cost pool with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would significantly alter the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized. Gains and losses are evaluated on a case by case basis for each asset sale, and future sales may or may not result in such treatment. We did not record any gains or losses on divestments completed during the first quarter of 2017. In comparison, we recorded a gain of $145.1 million on asset divestments during the first quarter of 2016.

During the comparative period ended March 31, 2016, we recorded a gain of $7.1 million on the repurchase of US$172 million in outstanding senior notes at a discount to par value.

Depletion, Depreciation and Accretion (“DD&A”)

	Three months ended March 31,	
($ millions, except per BOE amounts)	2017	2016
DD&A expense	$ 60.6	$ 91.3
Per BOE	$ 7.92	$ 10.26

DD&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, 2017, DD&A decreased when compared to the same period of 2016 primarily due to the cumulative effects of asset impairments recorded during 2016 as well as lower overall production.

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.

The trailing twelve month average crude oil and natural gas prices increased in the first quarter of 2017 compared to a decrease during the same period in 2016. There were no non-cash impairments recorded in the three months ended March 31, 2017, compared to $46.2 million in the same period of 2016.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. The primary factors include future first-day-of-the-month commodity prices, reserves revisions, our capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. Although the trailing twelve month average commodity prices are approximately in line with current levels, there is the potential for prices to decline, impacting the ceiling value and resulting in non-cash impairments. See Note 5 to the Interim Financial Statements for trailing twelve month prices.

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 based on our net ownership interest and management’s estimate of costs to abandon and reclaim such assets and the timing of the cost to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $155.5 million at March 31, 2017, compared to $181.7 million at December 31, 2016. Asset retirement obligation settlements were $2.5 million during the first quarters of 2017 and 2016. As a result of our divestments in the first quarter of 2017, we have reduced our asset retirement obligation by $25.1 million or 14%.

Income Taxes

	Three months ended March 31,	
($ millions)	2017	2016
Current tax expense/(recovery)	$ 0.1	$ (0.2)
Deferred tax expenses/(recovery)	28.8	256.5
Total tax expense/(recovery)	$ 28.9	$ 256.3

We recorded a total tax expense of $28.9 million during the first quarter of 2017 compared to $256.3 million for the same period in 2016. The current quarter tax expense is primarily based on income reported in Canada and the U.S. compared to the first quarter of 2016 where we recorded an additional valuation allowance. We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will be realized. This assessment is primarily the result of projecting future taxable income using benchmark forward prices for 2017, held constant and adjusted for other significant items affecting taxable income. Our overall net deferred income tax asset was $700.2 million at March 31, 2017 (December 31, 2016 - $733.4 million).

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 under our bank credit facility and senior notes, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At March 31, 2017, our senior debt to adjusted EBITDA ratio was 0.9x and our net debt to adjusted funds flow ratio was 0.9x. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

Total debt net of cash and restricted cash at March 31, 2017 was $350.4 million, a decrease of 7% compared to $375.5 million at December 31, 2016. Total debt was comprised of $4.0 million of bank indebtedness and $740.0 million of senior notes less $393.6 million in cash, including restricted cash. Proceeds from the December, 2016 sale of our non-operated North Dakota properties are being held in escrow for a period of up to 180 days from the date of closing to facilitate possible future like-kind transactions in accordance with U.S. federal tax regulations. These proceeds have been classified as restricted cash on our balance sheet. At March 31, 2017, we were essentially undrawn on our $800 million bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 107% for the three months ended March 31, 2017, compared to 138% for the same period in 2016.

Our working capital deficiency, excluding cash, restricted cash and current deferred financial assets and liabilities, increased to $130.7 million at March 31, 2017 from $94.4 million at December 31, 2016. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

At March 31, 2017, 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, 2017:

Covenant Description		March 31, 2017
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(1)	3.5x	0.9x
Total debt to adjusted EBITDA	4.0x	0.9x
Total debt to capitalization	50%	22%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(2)	3.0x - 3.5x	0.9x
Senior debt to consolidated present value of total proved reserves(3)	60%	27%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0 x	20.6x

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.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended March 31, 2017 were $130.1 million and $845.2 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 shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.
(2) Senior debt to adjusted EBITDA may increase to 3.5x for a period of 6 months for the senior notes, after which the ratio decreases to 3.0x.
(3) Senior debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

Dividends

($ millions, except per share amounts)	Three months ended March 31, 2017	2016
Dividends to shareholders	$ 7.2	$ 14.5
Per weighted average share (Basic)	$ 0.03	$ 0.07

During the three months ended March 31, 2017, we reported total dividends of $7.2 million or $0.03 per share, compared to $14.5 million or $0.07 per share for the same period in 2016. Effective with our April 2016 payment, we reduced our monthly dividend from $0.03 per share to $0.01 per share to provide additional financial flexibility and balance adjusted funds flow with capital and dividends.

The dividend is part of our strategy to create shareholder value; however, a sustained low price environment may impact our ability to pay dividends. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Three months ended March 31, 2017	2016
Share capital ($ millions)	$ 3,386.9	$ 3,142.9
Common shares outstanding (thousands)	242,129	207,133
Weighted average shares outstanding – basic (thousands)	241,285	206,716
Weighted average shares outstanding – diluted (thousands)	246,358	206,716

During the first quarter of 2017, a total of 1,646,000 shares were issued pursuant to our LTI plans and accordingly, $21.0 million was transferred from paid-in capital to share capital (2016 – 594,000; $9.4 million). For further details, see Note 13 to the Interim Financial Statements.

On March 28, 2017, we filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces of Canada and a Registration Statement with the U.S. Securities Exchange Commission. The Shelf Prospectus allows us to offer and issue up to an aggregate amount of $2.0 billion of common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains in place.

At May 4, 2017, we had 242,128,944 shares outstanding.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

($ millions, except per unit amounts)	Three months ended March 31, 2017 Canada	U.S.	Total	Three months ended March 31, 2016 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	12,907	20,271	33,178	14,186	25,322	39,508
Natural gas liquids (bbls/day)	1,405	1,753	3,158	1,804	3,690	5,494
Natural gas (Mcf/day)	68,542	223,065	291,607	99,539	217,611	317,150
Total average daily production (BOE/day)	25,736	59,201	84,937	32,580	65,280	97,860
Pricing[2]						
Crude oil (per bbl)	$ 51.67	$ 61.26	$ 57.53	$ 26.55	$ 34.42	$ 31.59
Natural gas liquids (per bbl)	37.09	38.30	37.76	24.98	4.68	11.34
Natural gas (per Mcf)	3.65	3.62	3.63	2.01	1.66	1.77
Capital Expenditures						
Capital spending	$ 25.0	$ 95.4	$ 120.4	$ 19.1	$ 24.2	$ 43.3
Acquisitions	1.5	1.0	2.5	1.0	2.6	3.6
Divestments	0.9	—	0.9	(188.3)	0.5	(187.8)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 87.2	$ 190.5	$ 277.7	$ 56.7	$ 113.8	$ 170.5
Royalties	(11.9)	(38.0)	(49.9)	(5.4)	(22.4)	(27.8)
Production taxes	(1.1)	(9.3)	(10.4)	(0.8)	(6.6)	(7.4)
Cash operating expenses	(26.6)	(23.7)	(50.3)	(43.5)	(28.8)	(72.3)
Transportation costs	(4.4)	(25.2)	(29.6)	(3.6)	(22.1)	(25.7)
Netback before hedging	$ 43.2	$ 94.3	$ 137.5	$ 3.4	$ 33.9	$ 37.3
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (57.6)	$ —	$ (57.6)	$ (13.5)	$ —	$ (13.5)
General and administrative expense[4]	17.8	5.7	23.5	18.3	4.1	22.4
Current income tax expense/(recovery)	—	0.1	0.1	(0.3)	0.1	(0.2)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.
(4) 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	Diluted
2017				
First Quarter	$ 227.8	$ 76.3	$ 0.32	$ 0.31
2016				
Fourth Quarter	$ 217.4	$ 840.3	$ 3.49	$ 3.43
Third Quarter	188.3	(100.7)	(0.42)	(0.42)
Second Quarter	174.3	(168.5)	(0.77)	(0.77)
First Quarter	142.7	(173.7)	(0.84)	(0.84)
Total 2016	$ 722.7	$ 397.4	$ 1.75	$ 1.72
2015				
Fourth Quarter	$ 199.4	$ (625.0)	$ (3.03)	$ (3.03)
Third Quarter	228.3	(292.7)	(1.42)	(1.42)
Second Quarter	251.7	(312.5)	(1.52)	(1.52)
First Quarter	205.0	(293.2)	(1.42)	(1.42)
Total 2015	$ 884.4	$ (1,523.4)	$ (7.39)	$ (7.39)

Oil and natural gas sales, net of royalties, increased slightly in the first quarter of 2017 compared to the fourth quarter of 2016 due to higher realized crude oil and natural gas prices partially offset by lower oil and natural gas liquids production volumes. Oil and gas sales, net of royalties, decreased throughout 2015 and 2016 as commodity prices declined. During 2015, the impact of weak commodity prices was somewhat offset by increasing production. Net losses reported in 2015 and 2016 were primarily due to non-cash asset impairments and valuation allowances on our deferred tax asset related to the decrease in the trailing twelve month average commodity prices, along with reduced revenues. Net income in the fourth quarter of 2016 related primarily to the reversal of the valuation allowance on our deferred tax asset.

2017 UPDATED GUIDANCE

We are reducing our operating expense guidance to $6.85/BOE from $7.25/BOE and narrowing our expected 2017 average Marcellus differential to US$0.60/Mcf below NYMEX from US$0.90/Mcf. All other guidance is unchanged and is summarized below. This guidance includes our previously announced divestments of certain non-core Canadian properties, but does not include any additional acquisitions or divestments.

Summary of 2017 Expectations	**Target**
Capital spending	$450 million
Average annual production	81,000 – 85,000 BOE/day
Fourth quarter average production	86,000 – 91,000 BOE/day
Average annual crude oil and natural gas liquids production	38,500 – 41,500 bbls/day
Fourth quarter average annual crude oil and natural gas liquids production	43,000 – 48,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	24%
Operating expenses	$6.85/BOE (from $7.25/BOE)
Transportation costs	$4.00/BOE
Cash G&A expenses	$1.85/BOE

2017 Differential/Basis Outlook[1]	
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.50)/bbl
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.60)/Mcf (from US$(0.90)/Mcf)

(1) Excluding transportation costs.

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. Netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

Calculation of Netback	**Three months ended March 31,**	
($ millions)	**2017**	**2016**
Oil and natural gas sales	$ 277.7	$ 170.5
Less:		
Royalties	(49.9)	(27.8)
Production taxes	(10.4)	(7.4)
Cash operating expenses[1]	(50.3)	(72.3)
Transportation costs	(29.6)	(25.7)
Netback before hedging	$ 137.5	$ 37.3
Cash gains/(losses) on derivative instruments	6.6	39.6
Netback after hedging	$ 144.1	$ 76.9

(1) Total operating expenses adjusted to exclude non-cash losses on fixed price electricity swaps of $0.1 million and $0.3 million in the three months ended March 31, 2017 and 2016, respectively.

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

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	Three months ended March 31,	
($ millions)	2017	2016
Cash flow from operating activities	$ 127.9	$ 69.7
Asset retirement obligation expenditures	2.5	2.5
Changes in non-cash operating working capital	(10.5)	(30.5)
Adjusted funds flow	$ 119.9	$ 41.7

"**Net debt to adjusted funds flow ratio**" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The net debt to adjusted funds flow ratio is calculated as total debt net of cash and restricted cash divided by a trailing twelve months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") and is not a debt covenant.

"**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 adjusted funds flow.

Calculation of Adjusted Payout Ratio	Three months ended March 31,	
($ millions)	2017	2016
Dividends	$ 7.2	$ 14.5
Capital and office expenditures	120.5	43.3
Sub-total	$ 127.7	$ 57.8
Funds flow	$ 119.9	$ 41.7
Adjusted payout ratio (%)	107%	138%

"Adjusted EBITDA" is used by Enerplus and its lenders to determine compliance with financial covenants under its bank credit facility and outstanding senior notes.

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	March 31, 2017
Net income	$ 647.4
Add:	
Interest	40.9
Current and deferred tax expense/(recovery)	(464.7)
DD&A and asset impairment	553.4
Other non-cash charges(2)	72.1
Sub-total	$ 849.1
Adjustment for material acquisitions and divestments(3)	(3.9)
Adjusted EBITDA	$ 845.2

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at March 31, 2017 include the three months ended March 31, 2017 and the second, third and fourth quarters of 2016.
(2) Includes the change in fair value of commodity derivatives, fixed price electricity swaps and equity swaps, non-cash SBC, and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than $50 million as if that acquisition or disposition had been made at the beginning of the period.

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 "total debt net of cash and restricted cash", "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "maximum debt to consolidated present value of total proved reserves" and "adjusted 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.

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 Issuer's 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, 2017, 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, 2017 and ended March 31, 2017 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 ("AIF"), 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 statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "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 2017 total, second half 2017, and fourth quarter 2017 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 adjusted funds flow; the results from our drilling program and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program in 2017 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 G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2017 and impact thereof on our production levels and land holdings; potential future asset and goodwill impairments, as well as relevant factors that may affect such 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 net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes and to negotiate relief if required; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; 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 and expectations and assumptions of Enerplus 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 curtailment of production and/or reduced realized prices; current commodity price, differentials 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 contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; the availability of third party services; and the extent of our liabilities. In addition, our updated 2017 guidance contained in this MD&A is based on the following: a WTI price of US$55.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.75/GJ and a USD/CDN exchange rate of 1.35. Enerplus believes 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: continued low commodity prices environment or 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; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent 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 identified in our AIF and Form 40-F as at December 31, 2016).