Exhibit 99.1

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

The following discussion and analysis of financial results is dated May 2, 2018 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three months ended March 31, 2018 and 2017 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015; and
- our MD&A for the year ended December 31, 2017 (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. Certain prior period amounts have been restated to conform with current period presentation.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 bbl and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcf. 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 Canadian peers.

Effective in 2018, Enerplus adopted ASC 606 - *Revenue from contracts with customers*. The adoption of this standard had no impact on the Interim Financial Statements, with the exception of additional note disclosures. See Notes 3(a) and 10 to the Interim Financial Statements for further details.

OVERVIEW

Average daily production for the quarter was 85,080 BOE/day, a decrease of 4% from 88,590 BOE/day in the fourth quarter of 2017. Production decreased in North Dakota as a result of downtime related to completions activities on adjacent properties, along with the expected decrease in volumes with wells coming on-stream toward the end of the quarter. The decrease in crude oil volumes was offset slightly by higher natural gas production in the Marcellus due to improved regional prices. We are well positioned to meet our annual average production guidance ranges of 86,000 – 91,000 BOE/day and our crude oil and natural gas liquids guidance of 46,000 – 50,000 bbls/day, with second quarter crude oil and natural gas liquids production of 48,000 – 50,000 bbls/day.

Capital expenditures of $151.5 million in the first quarter were in line with our expectations. The majority of our capital spending was directed to our crude oil properties, primarily in North Dakota. We are maintaining our 2018 annual capital spending guidance of between $535 and $585 million.

Operating costs for the quarter increased to $53.8 million or $7.02/BOE from $52.1 million or $6.39/BOE in the fourth quarter of 2017. Cash G&A expenses for the first quarter were $13.2 million or $1.72/BOE compared to $12.6 million or $1.55/BOE in the fourth quarter of 2017. The increase in operating costs and cash G&A expenses on a per BOE basis was primarily due to lower production volumes. We are maintaining our annual guidance targets of $7.00/BOE for operating costs and $1.65/BOE for cash G&A expenses.

We continued to add to our commodity hedge positions during the quarter. As of May 2, 2018, we had approximately 67% of our forecasted crude oil production, net of royalties, hedged for the remainder of 2018, and approximately 66% and 19% of our crude oil production, net of royalties, hedged in 2019 and 2020, respectively, based on 2018 forecasted production. We have also hedged approximately 21% of our forecasted natural gas production, net of royalties, for the remainder of 2018.

We recorded net income of $29.6 million and adjusted funds flow of $155.2 million in the first quarter of 2018, compared to $15.3 million and $199.6 million, respectively, in the fourth quarter of 2017. Net income in the fourth quarter was impacted by the re-measurement of our U.S. deferred tax assets as a result of the reduction in the U.S. federal income tax rate in 2017. Both fourth quarter net income and adjusted funds flow benefited from a $50.1 million U.S. Alternative Minimum Tax ("AMT") credit carryover, which we expect to realize in 2018.

At March 31, 2018, our total debt net of cash was $292.0 million and our net debt to adjusted funds flow ratio was 0.5x.

RESULTS OF OPERATIONS

Production

Average daily production for the first quarter totaled 85,080 BOE/day, compared to production of 88,590 BOE/day in the fourth quarter of 2017. Crude oil and liquids production decreased by 5,294 bbls/day, primarily due to lower North Dakota volumes, where we experienced downtime due to completions activities on adjacent properties, along with the expected timing of wells coming on-stream later in the quarter. As a result of improved realized prices, we did not have any production curtailments in the Marcellus during the quarter, which contributed to a 4% increase in natural gas production compared to the fourth quarter of 2017.

Production in the first quarter was consistent with production of 84,937 BOE/day for the same period of the prior year. Our increased capital program in North Dakota resulted in an increase of approximately 9,000 BOE/day of liquids production along with slightly higher Marcellus natural gas production. These increases were offset by the divestment of non-core Canadian properties throughout 2017 and the first quarter of 2018 with associated production of approximately 8,300 BOE/day.

Our crude oil and natural gas liquids weighting increased to 49% in the first quarter of 2018, from 43% for the same period of 2017, due to increased capital spending on our North Dakota crude oil asset and the divestment of non-core natural gas weighted properties.

Average daily production volumes for the three months ended March 31, 2018 and 2017 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2018**	**2017**	**% Change**
Crude oil (bbls/day)	37,443	33,178	13%
Natural gas liquids (bbls/day)	4,085	3,158	29%
Natural gas (Mcf/day)	261,310	291,607	(10%)
Total daily sales (BOE/day)	85,080	84,937	0%

We are well positioned to meet our annual average production guidance ranges of 86,000 – 91,000 BOE/day and our crude oil and natural gas liquids guidance of 46,000 – 50,000 bbls/day, with second quarter crude oil and natural gas liquids production of 48,000 – 50,000 bbls/day.

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 average prices for the three months ended March 31, 2018 and 2017 and quarterly average prices for the periods indicated:

Pricing (average for the period)	**Q1 2018**	**Q4 2017**	**Q3 2017**	**Q2 2017**	**Q1 2017**
Benchmarks					
WTI crude oil (US$/bbl)	$ 62.87	$ 55.40	$ 48.20	$ 48.29	$ 51.92
AECO natural gas – monthly index ($/Mcf)	1.85	1.96	2.04	2.77	2.94
AECO natural gas – daily index ($/Mcf)	2.08	1.69	1.45	2.78	2.69
NYMEX natural gas – last day (US$/Mcf)	3.00	2.93	3.00	3.18	3.32
USD/CDN average exchange rate	1.26	1.27	1.25	1.34	1.32
USD/CDN period end exchange rate	1.29	1.26	1.25	1.30	1.33
Enerplus selling price(1)					
Crude oil ($/bbl)	$ 69.67	$ 65.91	$ 54.21	$ 55.66	$ 57.53
Natural gas liquids ($/bbl)	28.13	32.26	26.22	25.14	37.76
Natural gas ($/Mcf)	3.50	3.03	2.58	3.48	3.63
Average differentials					
MSW Edmonton – WTI (US$/bbl)	$ (5.89)	$ (1.14)	$ (2.89)	$ (2.26)	$ (3.54)
WCS Hardisty – WTI (US$/bbl)	(24.28)	(12.27)	(9.94)	(11.13)	(14.58)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.67)	(1.32)	(1.29)	(0.60)	(0.63)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.76)	(1.40)	(1.36)	(0.66)	(0.70)
AECO monthly – NYMEX (US$/Mcf)	(1.44)	(1.40)	(1.39)	(1.13)	(1.10)
Enerplus realized differentials(1)(2)					
Canada crude oil – WTI (US$/bbl)	$ (20.82)	$ (10.47)	$ (9.29)	$ (11.02)	$ (12.76)
Canada natural gas – NYMEX (US$/Mcf)	(0.52)	(0.56)	(1.00)	(0.51)	(0.56)
Bakken crude oil – WTI (US$/bbl)	(3.27)	(1.61)	(3.24)	(5.43)	(5.59)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.21)	(0.81)	(1.02)	(0.64)	(0.60)

(1) Excluding transportation costs, royalties and commodity derivative instruments.
(2) Based on a weighted average differential for the period.

CRUDE OIL AND NATURAL GAS LIQUIDS

Our average realized crude oil price increased by 6% from the fourth quarter of 2017 to average $69.67/bbl. In comparison, benchmark WTI crude oil prices increased by 13% due to lower global crude oil inventories and uncertainty as to when the Organization of the Petroleum Exporting Countries (“OPEC”) production agreement will end. This price strength was partially offset by weaker crude oil differentials in both the U.S. and Canada as Canadian crude was restricted due to pipeline egress limitations.

Our realized Bakken price differential to WTI increased by US$1.66/bbl from the fourth quarter of 2017 to average US$3.27/bbl below WTI as stronger WTI prices continue to drive growth in North American crude oil supply. Although this resulted in an increase in differentials for light sweet crude oil in both Canada and the U.S. during the quarter, the overall price received for our Bakken production increased by 11% due to the strength in WTI benchmark prices. As a result of the significant improvement in WTI prices, we are revising our expected 2018 average U.S. Bakken crude oil differential to US$3.50/bbl below WTI based on a WTI price of US$65.00/bbl.

Our realized price differential for our Canadian crude oil production increased by US$10.35/bbl compared to the previous quarter. Canadian crude oil prices deteriorated in the quarter due to pipeline apportionments and continued pipeline flow restrictions following the late 2017 service disruption on the Keystone pipeline. Our realized price for natural gas liquids averaged $28.13/bbl during the period, a decrease of 13% compared to the previous quarter primarily due to weakness in benchmark prices, particularly in propane markets.

NATURAL GAS

Our average realized natural gas price during the first quarter increased by 16% compared to the fourth quarter of 2017 to average $3.50/Mcf, due to a significant improvement in realized prices for our Marcellus production. Comparatively, benchmark NYMEX natural gas prices increased by 2% during the quarter.

Our realized Marcellus sales price differential, excluding transportation and gathering costs, improved considerably from the fourth quarter of 2017 to average US$0.21/Mcf below NYMEX. This outperformed the Benchmark monthly Transco Leidy price which averaged US$0.67/Mcf below NYMEX during the quarter. Our Marcellus portfolio benefitted from the impacts of a colder than normal winter, particularly in early January of 2018, when record cold weather resulted in price spikes in key consumption regions in the U.S. We expect our Marcellus differential to increase during the remainder of 2018 as a portion of our sales portfolio is tied to New York markets that are typically weaker during the summer months. We continue to expect our Marcellus differentials to average US$0.40/Mcf below NYMEX for 2018.

Although benchmark AECO gas prices remained weak due to delivery limitations on export pipelines out of the basin, our realized Canadian natural gas price differential averaged US$0.52/Mcf below NYMEX. We continue to benefit from our multi-year term AECO physical sales contracts, which have an average fixed basis differential of US$0.63/Mcf below NYMEX.

FOREIGN EXCHANGE

The USD/CDN exchange rate was 1.29 USD/CDN at March 31, 2018, and averaged 1.26 USD/CDN during the first quarter of 2018, compared to an exchange rate of 1.26 USD/CDN at December 31, 2017 and an average exchange rate of 1.27 USD/CDN during the fourth quarter of 2017. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices, and a stronger Canadian dollar relative to the U.S. dollar decreases the amount of our realized sales. Because we report in Canadian dollars, the stronger Canadian dollar also decreases our U.S. dollar denominated costs, capital spending and the interest cost on 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 2, 2018, we have hedged approximately 21,500 bbls/day of our expected crude oil production for the remainder of 2018, which represents approximately 67% of our forecasted crude oil production, after royalties. For 2019 and 2020, we are hedged on approximately 21,300 bbls/day or 66% and 6,000 bbls/day or 19%, respectively, of our 2018 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, 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 funds flow.

As of May 2, 2018, we have hedged approximately 37,800 Mcf/day of our forecasted natural gas production for the remainder of 2018. This represents approximately 21% of our forecasted natural gas production, after royalties.

The following is a summary of our financial contracts in place at May 2, 2018, expressed as a percentage of our forecasted 2018 net production volumes:

	WTI Crude Oil (US$/bbl)[(1)]						
	Apr 1, 2018 – Apr 30, 2018	May 1, 2018 – Jun 30, 2018	Jul 1, 2018 – Sep 30, 2018	Oct 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Jan 1, 2020 – Dec 31, 2020
Swaps							
Sold Swaps	$ 55.38	$ 57.20	$ 53.73	$ 53.73	$ 53.73	—	—
%	16%	19%	9%	9%	9%	—	—
Three Way Collars							
Sold Puts	$ 42.92	$ 42.92	$ 42.71	$ 42.74	$ 44.05	$ 44.26	$ 46.67
%	47%	47%	56%	62%	50%	68%	19%
Purchased Puts	$ 52.90	$ 52.90	$ 52.53	$ 52.48	$ 53.69	$ 54.17	$ 56.00
%	47%	47%	56%	62%	50%	68%	19%
Sold Calls	$ 61.73	$ 61.73	$ 61.22	$ 61.10	$ 63.44	$ 64.83	$ 70.33
%	47%	47%	56%	62%	50%	68%	19%

(1) Based on weighted average price (before premiums) assuming average annual production of 88,500 BOE/day, which is the mid-point of our annual 2018 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.

	NYMEX Natural Gas (US$/Mcf)[1]	
	Apr 1, 2018 – Oct 31, 2018	**Nov 1, 2018 – Dec 31, 2018**
Collars		
Purchased Puts	$ 2.75	$ 2.75
%	22%	16%
Sold Calls	$ 3.38	$ 3.47
%	22%	16%

(1) Based on weighted average price (before premiums) assuming average annual production of 88,500 BOE/day, which is the mid-point of our annual 2018 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended March 31,	
($ millions)	**2018**	**2017**
Cash gains/(losses):		
Crude oil	$ (6.4)	$ (1.0)
Natural gas	16.5	7.6
Total cash gains/(losses)	$ 10.1	$ 6.6
Non-cash gains/(losses):		
Crude oil	$ (29.9)	$ 44.4
Natural gas	(0.7)	6.6
Total non-cash gains/(losses)	$ (30.6)	$ 51.0
Total gains/(losses)	$ (20.5)	$ 57.6

	Three months ended March 31,	
(Per BOE)	**2018**	**2017**
Total cash gains/(losses)	$ 1.33	$ 0.86
Total non-cash gains/(losses)	(3.99)	6.67
Total gains/(losses)	$ (2.66)	$ 7.53

During the first quarter of 2018, we realized cash losses of $6.4 million on our crude oil contracts and cash gains of $16.5 million on our natural gas contracts. In comparison, 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. Cash losses on crude oil contracts were primarily due to crude oil prices rising above the sold call strike price on our three way collar hedge positions. Cash gains recorded in the quarter on our natural gas contracts included a gain of $15.1 million on the unwind of a portion of our AECO-NYMEX basis physical contracts.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as 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 2018, the fair value of our crude oil contracts was in a net liability position of $64.1 million, while the fair value of our natural gas contracts was in a net asset position of $1.0 million. For the three months ended March 31, 2018, the change in the fair value of our crude oil contracts and natural gas contracts represented losses of $29.9 million and $0.7 million, respectively.

Revenues

	Three months ended March 31,	
($ millions)	**2018**	**2017**
Oil and natural gas sales	$ 328.5	$ 277.7
Royalties	(63.5)	(49.9)
Oil and natural gas sales, net of royalties	$ 265.0	$ 227.8

Oil and natural gas sales, net of royalties for the three months ended March 31, 2018, were $265.0 million an increase of 16% from the same period in 2017. The increase in revenue was a result of the improvement in crude oil prices compared to the prior year, along with a higher crude oil and natural gas liquids weighting of 49% compared to 43%.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended March 31, 2018	2017
Royalties	$ 63.5	$ 49.9
Per BOE	$ 8.30	$ 6.53
Production taxes	$ 16.1	$ 10.4
Per BOE	$ 2.11	$ 1.36
Royalties and production taxes	$ 79.6	$ 60.3
Per BOE	$ 10.41	$ 7.89
Royalties and production taxes (% of oil and natural gas sales)	24%	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. 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, 2018, royalties and production taxes increased to $79.6 million from $60.3 million for the same period in 2017 primarily due to higher crude oil prices and a greater weighting of our production coming from our U.S. properties, which have a combined royalty and production tax rate of approximately 26%. Royalties and production taxes averaged 24% of crude oil and natural gas sales before transportation in the first three months of 2018 compared to 22% for the same period in 2017.

We are maintaining our annual average royalty and production tax rate guidance of 25% for 2018.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended March 31, 2018	2017
Cash operating expenses	$ 53.8	$ 50.3
Non-cash (gains)/losses[1]	—	0.1
Total operating expenses	$ 53.8	$ 50.4
Per BOE	$ 7.02	$ 6.59

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

For the three months ended March 31, 2018, operating expenses were $53.8 million or $7.02/BOE compared to our annual guidance of $7.00/BOE. Operating costs increased by $3.4 million compared to the same period in 2017 mainly due to a greater proportion of our production coming from crude oil and natural gas liquids offset by the divestment of higher operating cost Canadian properties throughout 2017 and the first quarter of 2018.

We are maintaining our annual operating cost guidance of $7.00/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended March 31, 2018	2017
Transportation costs	$ 26.9	$ 29.6
Per BOE	$ 3.52	$ 3.88

For the three months ended March 31, 2018, transportation costs were $26.9 million or $3.52/BOE compared to our annual guidance of $3.60/BOE. During the same period in 2017 transportation costs were $29.6 million or $3.88/BOE. The decrease is primarily due to the divestment of non-core Canadian natural gas properties in 2017 and a stronger Canadian dollar during the first quarter of 2018, which lowered the cost of our U.S. transportation expenses.

We are maintaining our annual guidance for transportation costs of $3.60/BOE.

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, 2018		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	44,050 BOE/day	246,180 Mcfe/day	85,080 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 62.99	$ 3.56	$ 42.91
Royalties and production taxes	(16.47)	(0.65)	(10.41)
Cash operating expenses	(10.79)	(0.50)	(7.02)
Transportation costs	(2.07)	(0.84)	(3.52)
Netback before hedging	$ 33.66	$ 1.57	$ 21.96
Cash gains/(losses)	(1.61)	0.75	1.33
Netback after hedging	$ 32.05	$ 2.32	$ 23.29
Netback before hedging ($ millions)	$ 133.4	$ 34.8	$ 168.2
Netback after hedging ($ millions)	$ 127.0	$ 51.3	$ 178.3

	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

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

Crude oil netbacks per BOE before hedging were higher for the three months ended March 31, 2018 compared to the same period in 2017 primarily due to higher crude oil sales and improved realized prices. Natural gas netbacks before hedging were lower for the first quarter of 2018 compared to the same period in 2017 mainly due to lower production with the divestment of non-core Canadian natural gas properties and weaker realized prices. For the three months ended March 31, 2018, our crude oil properties accounted for 79% of our netback before hedging, compared to 63% during the same period in 2017.

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 11 and Note 14 to the Interim Financial Statements for further details.

	Three months ended March 31,	
($ millions)	**2018**	**2017**
Cash:		
G&A expense	$ 13.2	$ 14.3
Share-based compensation expense	1.9	0.2
Non-Cash:		
Share-based compensation expense	9.1	8.1
Equity swap loss/(gain)	(1.0)	0.9
Total G&A expenses	$ 23.2	$ 23.5

(Per BOE)	Three months ended March 31, 2018	2017
Cash:		
G&A expense	$ 1.72	$ 1.87
Share-based compensation expense	0.25	0.02
Non-Cash:		
Share-based compensation expense	1.19	1.06
Equity swap loss/(gain)	(0.13)	0.12
Total G&A expenses	$ 3.03	$ 3.07

For the three months ended March 31, 2018, cash G&A expenses were $13.2 million or $1.72/BOE compared to $14.3 million or $1.87/BOE for the same period in 2017. The decrease in cash G&A expenses from the prior year was primarily due to the impact of reductions in staff levels throughout 2017 as we continued to focus our business through asset divestments.

During the quarter, we reported cash SBC expense of $1.9 million due to the grant of additional deferred share units and the increase in our share price on outstanding deferred share units. In comparison, during the same period of 2017, we recorded cash SBC expense of $0.2 million. We recorded non-cash SBC of $9.1 million or $1.19/BOE in the first quarter of 2018, which was in line with $8.1 million or $1.06/BOE during the same period in 2017.

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 gain of $1.0 million on these hedges due to the increase in our share price. As of March 31, 2018 we had 470,000 units hedged at a weighted average price of $16.89 per share.

We are maintaining our annual cash G&A guidance of $1.65/BOE.

Interest Expense

For the three months ended March 31, 2018, we recorded total interest expense of $9.1 million compared to $10.1 million for the same period in 2017. The decrease in interest expense for the three month period was primarily due to the impact of a strengthening Canadian dollar on our U.S. dollar denominated interest expense, along with the payment of our first installment of US$22 million on our US$110 million senior notes, which carry a higher coupon rate, during the second quarter of 2017.

At March 31, 2018, we were undrawn on our $800 million bank credit facility and our debt balance consisted entirely of fixed interest rate senior notes with a weighted average interest rate of 4.8%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended March 31, 2018	2017
Realized:		
Foreign exchange (gain)/loss on settlements	$ 0.1	$ 0.1
Translation of U.S. dollar cash held in Canada (gain)/loss	(7.3)	—
Unrealized (gain)/loss	17.6	(3.9)
Total foreign exchange (gain)/loss	$ 10.4	$ (3.8)
USD/CDN average exchange rate	1.26	1.32
USD/CDN period end exchange rate	1.29	1.33

For the three months ended March 31, 2018, we recorded a net foreign exchange loss of $10.4 million compared to a gain of $3.8 million for the same period in 2017. Realized gains and losses include day-to-day transactions recorded in foreign currencies, and the translation of our U.S. dollar denominated cash held in Canada, 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 the period end exchange rate at March 31, 2018 to December 31, 2017, the Canadian dollar weakened relative to the U.S. dollar, resulting in an unrealized loss of $17.6 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended March 31, 2018	2017
Capital spending	$ 151.5	$ 120.4
Office capital	1.4	0.1
Sub-total	152.9	120.5
Property and land acquisitions	$ 12.3	$ 2.5
Property divestments	(7.0)	0.9
Sub-total	5.3	3.4
Total [(1)]	$ 158.2	$ 123.9

(1) Excludes changes in non-cash investing working capital. See Note 17(b) to the Interim Financial Statements for further details.

Capital spending for the three months ended March 31, 2018, totaled $151.5 million compared to the $120.4 million for the same period in 2017. The increase in spending is in line with our strategy to deliver production and liquids growth through 2018. During the quarter we spent $121.5 million on our U.S. crude oil properties, $16.8 million on our Marcellus natural gas assets and $12.1 million on our Canadian waterflood properties.

In the first quarter, we completed $12.3 million in property and land acquisitions which included minor acquisitions of leases and undeveloped land. During the first quarter, property divestments totaled $7.0 million primarily related to an acreage swap in North Dakota and the divestment of non-core properties in N.W. Alberta with associated production of approximately 600 BOE/day.

We continue to expect annual capital spending of $535 to $585 million.

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

($ millions, except per BOE amounts)	Three months ended March 31, 2018	2017
DD&A expense	$ 64.0	$ 60.6
Per BOE	$ 8.36	$ 7.92

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, 2018, DD&A increased compared to the same period of 2017 as a result of an increased weighting of U.S. production with higher depletion rates.

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 $118.6 million at March 31, 2018, compared to $117.7 million at December 31, 2017. For the three months ended March 31, 2018, asset retirement obligation settlements were $3.3 million compared to $2.5 million during the same period in 2017. As a result of our divestments in the first quarter of 2018, we have reduced our asset retirement obligation by $3.7 million. See Note 9 to the Interim Financial Statements for further details.

Income Taxes

($ millions)	Three months ended March 31, 2018	2017
Current tax expense/(recovery)	$ 0.1	$ 0.1
Deferred tax expenses/(recovery)	12.4	28.8
Total tax expense/(recovery)	$ 12.5	$ 28.9

We recorded a total tax expense of $12.5 million during the first quarter of 2018 compared to $28.9 million for the same period in 2017. The decrease in the total tax expense is due to lower overall income in 2018, as well as a reduction to the U.S. federal income tax rate to 21% from 35% effective January 1, 2018 with the enactment of the U.S. Tax Cuts and Jobs Act. See Note 13 to the Interim Financial Statements for further details.

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, 2018, our senior debt to adjusted EBITDA ratio was 1.2x and our net debt to adjusted funds flow ratio was 0.5x. 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 at March 31, 2018 was $292.0 million, a decrease of 10% compared to $325.8 million at December 31, 2017. Total debt was comprised of $688.4 million of senior notes less $396.4 million in cash. At March 31, 2018, we were 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 103% for the three months ended March 31, 2018, compared to 107% for the same period in 2017.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, increased to $162.6 million at March 31, 2018 from $107.6 million at December 31, 2017. 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, 2018, 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 under our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at March 31, 2018:

Covenant Description		March 31, 2018
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.2x
Total debt to adjusted EBITDA (1)	4.0x	1.2x
Total debt to capitalization	50%	21%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.2x
Senior debt to consolidated present value of total proved reserves(3)	60%	26%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	16.4x

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, 2018 was $171.7 million and $619.5 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 for the senior notes 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

	Three months ended March 31,	
($ millions, except per share amounts)	2018	2017
Dividends to shareholders	$ 7.3	$ 7.2
Per weighted average share (Basic)	$ 0.03	$ 0.03

During the three months ended March 31, 2018, we reported total dividends of $7.3 million or $0.03 per share compared to $7.2 million or $0.03 per share for the same period in 2017.

The dividend is part of our strategy to create shareholder value. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Three months ended March 31, 2018	2017
Share capital ($ millions)	$ 3,411.9	$ 3,386.9
Common shares outstanding (thousands)	244,773	242,129
Weighted average shares outstanding – basic (thousands)	243,874	241,285
Weighted average shares outstanding – diluted (thousands)	249,191	246,358

During the first quarter, a total of 2,644,000 shares were issued pursuant to our stock option plan and treasury-settled LTI plans and $23.5 million was transferred from paid-in capital to share capital (2017 – 1,646,000; $21.0 million). For further details, see Note 14 to the Interim Financial Statements.

On March 21, 2018, Enerplus announced the acceptance of its Normal Course Issuer Bid ("the bid") by the Toronto Stock Exchange ("TSX"). The bid allows Enerplus to purchase up to 17,095,598 common shares on the TSX, the New York Stock Exchange and/or alternative Canadian trading systems over a period of twelve months commencing on March 26, 2018. All common shares purchased under the bid will be cancelled. For the period ended March 31, 2018, no common shares were purchased.

At May 2, 2018, we had 244,823,365 common shares outstanding. In addition, an aggregate of 11,866,379 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU"), Restricted Share Unit, and stock option plans, assuming the maximum payout multiplier of 2.0 times for the PSUs.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2018			Three months ended March 31, 2017		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	9,513	27,930	37,443	12,907	20,271	33,178
Natural gas liquids (bbls/day)	1,247	2,838	4,085	1,405	1,753	3,158
Natural gas (Mcf/day)	33,132	228,178	261,310	68,542	223,065	291,607
Total average daily production (BOE/day)	16,282	68,798	85,080	25,736	59,201	84,937
Pricing[2]						
Crude oil (per bbl)	$ 52.82	$ 75.41	$ 69.67	$ 51.67	$ 61.26	$ 57.53
Natural gas liquids (per bbl)	45.11	20.66	28.13	37.09	38.30	37.76
Natural gas (per Mcf)	3.12	3.56	3.50	3.65	3.62	3.63
Capital Expenditures						
Capital spending	$ 13.2	$ 138.3	$ 151.5	$ 25.0	$ 95.4	$ 120.4
Acquisitions	1.1	11.2	12.3	1.5	1.0	2.5
Divestments	(0.9)	(6.1)	(7.0)	0.9	—	0.9
Netback[3] **Before Hedging**						
Oil and natural gas sales	$ 60.7	$ 267.8	$ 328.5	$ 87.2	$ 190.5	$ 277.7
Royalties	(9.9)	(53.6)	(63.5)	(11.9)	(38.0)	(49.9)
Production taxes	(0.8)	(15.3)	(16.1)	(1.1)	(9.3)	(10.4)
Cash operating expenses	(20.6)	(33.2)	(53.8)	(26.6)	(23.7)	(50.3)
Transportation costs	(3.0)	(23.9)	(26.9)	(4.4)	(25.2)	(29.6)
Netback before hedging	$ 26.4	$ 141.8	$ 168.2	$ 43.2	$ 94.3	$ 137.5
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 20.5	$ —	$ 20.5	$ (57.6)	$ —	$ (57.6)
General and administrative expense[4]	15.4	7.8	23.2	17.8	5.7	23.5
Current income tax expense/(recovery)	—	0.1	0.1	—	0.1	0.1

(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	Net Income/(Loss) Per Share Diluted
2018				
First Quarter	$ 265.0	$ 29.6	$ 0.12	$ 0.12
Total 2018	$ 265.0	$ 29.6	$ 0.12	$ 0.12
2017				
Fourth Quarter	$ 271.1	$ 15.3	$ 0.06	$ 0.06
Third Quarter	196.1	16.1	0.07	0.07
Second Quarter	225.7	129.3	0.53	0.52
First Quarter	227.8	76.3	0.32	0.31
Total 2017	$ 920.7	$ 237.0	$ 0.98	$ 0.96
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

Oil and natural gas sales, net of royalties, decreased slightly in the first quarter of 2018 compared to the fourth quarter of 2017 due to decreased production volumes offset by higher realized prices. Net income increased in the first quarter of 2018 due to the higher deferred income tax expense recorded in the fourth quarter of 2017 as a result of re-measurement of our U.S. deferred tax assets for the U.S. federal income tax rate reduction. Oil and natural gas sales, net of royalties, increased in 2017 compared to 2016 due to an increase in realized commodity prices, offset by a decrease in production due to non-core asset divestments. Net income for 2017 decreased from 2016, due to lower gains recorded on asset divestments, along with an increase in deferred tax expense. Net income was higher in the second quarter of 2017 due to a $78.4 million gain recorded on the divestment of certain Canadian assets.

2018 UPDATED GUIDANCE

Our 2018 guidance is summarized below. We have included second quarter 2018 crude oil and natural gas liquids production guidance of 48,000 – 50,000 bbls/day and revised our 2018 average U.S. Bakken crude oil differential to US$3.50/bbl below WTI.

All other guidance targets remain unchanged. This guidance does not include any additional acquisitions or divestments.

Summary of 2018 Expectations	Target
Capital spending	$535 – $585 million
Average second quarter crude oil and natural gas liquids production	48,000 - 50,000 bbls/day
Average annual production	86,000 – 91,000 BOE/day
Average annual crude oil and natural gas liquids production	46,000 – 50,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$7.00/BOE
Transportation costs	$3.60/BOE
Cash G&A expenses	$1.65/BOE

2018 Differential/Basis Outlook[1]	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.50)/bbl (from US$(2.50)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.40)/Mcf

(1) Excludes 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)	2018	2017
Oil and natural gas sales	$ 328.5	$ 277.7
Less:		
Royalties	(63.5)	(49.9)
Production taxes	(16.1)	(10.4)
Cash operating expenses(1)	(53.8)	(50.3)
Transportation costs	(26.9)	(29.6)
Netback before hedging	$ 168.2	$ 137.5
Cash gains/(losses) on derivative instruments	10.1	6.6
Netback after hedging	$ 178.3	$ 144.1

(1) Total operating expenses have been adjusted to exclude a non-cash loss of $0.1 million for the three months ended March 31, 2017 (Three months ended March 31, 2018 – nil).

"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)	2018	2017
Cash flow from operating activities	$ 159.3	$ 127.9
Asset retirement obligation expenditures	3.3	2.5
Changes in non-cash operating working capital	(7.4)	(10.5)
Adjusted funds flow	$ 155.2	$ 119.9

"Total debt net of cash" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. Total debt net of cash is calculated as senior notes plus any outstanding bank credit facility balance, minus cash and restricted cash.

"**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 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)	2018	2017
Dividends	$ 7.3	$ 7.2
Capital and office expenditures	152.9	120.5
Sub-total	$ 160.2	$ 127.7
Adjusted funds flow	$ 155.2	$ 119.9
Adjusted payout ratio (%)	103%	107%

"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, 2018
Net income/(loss)	$	190.3
Add:		
Interest		37.7
Current and deferred tax expense/(recovery)		65.7
DD&A and asset impairment		254.2
Other non-cash charges(2)		75.9
Sub-total	$	623.8
Adjustment for material acquisitions and divestments(3)		(4.3)
Adjusted EBITDA	$	619.5

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at March 31, 2018 include the three months ended March 31, 2018 and the second, third and fourth quarter of 2017.
(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 "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, 2018, 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, 2018 and ended March 31, 2018 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 2018 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; anticipated production volumes subject to curtailment; 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 2018 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 2018 and impact thereof on our production levels; 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 beyond our current expectations; 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 2018 guidance contained in this MD&A is based on the following prices for the first quarter: a WTI price of US$65.00/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.00/GJ and a USD/CDN exchange rate of 1.27. 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 volatility in 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, our Annual MD&A and Form 40-F as at December 31, 2017).

The forward-looking information contained in this MD&A speak only as of the date of this MD&A. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.