

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

The following discussion and analysis of financial results is dated August 10, 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 and six months ended June 30, 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. 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 ("Mcf") based on 0.167 bbl:1 Mcf. BOE and Mcf 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 Mcf 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

Second quarter production averaged 86,209 BOE/day, compared to our annual average production guidance range of 81,000 – 85,000 BOE/day. As a result of our successful capital development program to date, we are increasing our annual guidance range to 84,000 – 86,000 BOE/day. Production increased by 2% when compared to the first quarter of 2017, which includes the impact of Canadian asset divestments completed during the first and second quarter of 2017 with combined production of 7,300 BOE/day. These divestments were offset by a 35% increase in North Dakota production with 8.6 net wells coming on-stream during the second quarter. With the growth in North Dakota, we produced 40,994 bbls/day of crude oil and natural gas liquids in the quarter, up from 36,336 bbls/day in the first quarter. As a result, we are raising the lower end of our crude oil and natural gas liquids range, and are now guiding to 39,500 – 41,500 bbls/day. We are maintaining our fourth quarter exit production guidance of 86,000 – 91,000 BOE/day and fourth quarter average crude oil and natural gas liquids range of 43,000 – 48,000 bbls/day.

Our capital spending for the second quarter totaled \$101.7 million, which was in line with expectations. Approximately 70% of our capital program was directed to our North Dakota crude oil properties, 17% to our Marcellus natural gas asset and 10% to our Canadian waterfloods. We are maintaining our 2017 annual capital spending guidance of \$450 million.

Operating expenses were \$45.8 million or \$5.83/BOE during the second quarter compared to our annual guidance of \$6.85/BOE. The decrease in operating costs from the first quarter of 2017 was mainly due to additional savings related to the previously announced divestment of higher operating cost Canadian assets, as well as strong production performance in Fort Berthold and Marcellus. As a result, we are reducing our annual guidance for operating expenses to \$6.40/BOE from \$6.85/BOE. We expect higher operating costs for the second half of the year as our liquids production weighting increases.

Cash G&A expenses for the second quarter were \$12.0 million or \$1.53/BOE compared to annual guidance of \$1.85/BOE. The decrease in our cash G&A expenses is primarily due to reductions in staff levels as we continue to focus the business through asset divestments, along with higher production during the quarter. Accordingly, we are lowering our cash G&A expense guidance to \$1.75/BOE from \$1.85/BOE. We are also reducing our transportation guidance to \$3.90/BOE from \$4.00/BOE.

During the quarter we closed the previously announced sale of Alberta shallow gas assets and the Brooks waterflood property for proceeds of \$59.6 million, with associated production of 5,600 BOE/day and asset retirement obligations of \$46.9 million. Second quarter earnings includes a gain of \$78.4 million related to this divestment.

We continued to add to our commodity hedge positions during the quarter. As of August 10, 2017, we have approximately 72% of our forecasted crude oil production, net of royalties, hedged for the remainder of 2017, and approximately 65% 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, for the remainder of 2017.

We recorded net income of \$129.3 million and adjusted funds flow of \$114.2 million in the second quarter, compared to \$76.3 million and \$119.9 million, respectively, in the first quarter of 2017. Both net income and adjusted funds flow benefited from the impact of increased volumes, as well as reductions in cash operating and G&A expenses. Net income also included the gain on our second quarter asset divestment.

At June 30, 2017, our total debt net of cash decreased to \$308.1 million and our net debt to adjusted funds flow ratio was 0.7x.

## RESULTS OF OPERATIONS

### Production

Production for the second quarter averaged 86,209 BOE/day, an increase of 1,272 BOE/day or 2% compared to the first quarter of 2017, despite the second quarter sale of certain Canadian assets with production of approximately 5,600 BOE/day. The strong performance from our Fort Berthold and Marcellus assets, a significant number of on-streams in North Dakota during the quarter, and a gas balancing adjustment related to our Marcellus assets contributed to higher production levels. Crude oil and liquids production increased by 4,658 bbls/day or 13% during the quarter, primarily due to 8.6 additional net wells brought on-stream in Fort Berthold as we continue to execute on our capital program. Natural gas production decreased by 7% from the first quarter, which was primarily due to the divestments in Canada which closed throughout the first and second quarters of 2017. As a result, our crude oil and natural gas liquids weighting during the second quarter increased to 48% from 43% in the first quarter of 2017.

For the three months ended June 30, 2017, crude oil and natural gas liquids volumes decreased by 2,914 bbls/day or 7% compared to the same period in the prior year. This was primarily due to the divestment of 5,000 BOE/day of our non-operated North Dakota assets on December 30, 2016, and the second quarter 2017 divestment of the Brooks waterflood property with approximately 1,800 bbls/day of crude oil and liquids production, partially offset by production growth out of North Dakota. Natural gas production decreased by 27,211 Mcf/day or 9% compared to the same period in 2016, as a result of the asset divestments in Canada from the third quarter of 2016 through the second quarter of 2017.

Average daily production volumes for the three and six months ended June 30, 2017 and 2016 are outlined below:

Average Daily Production Volumes	Three months ended June 30,			Six months ended June 30,		
	2017	2016	% Change	2017	2016	% Change
Crude oil (bbls/day)	36,861	39,079	(6%)	35,030	39,294	(11%)
Natural gas liquids (bbls/day)	4,133	4,829	(14%)	3,648	5,161	(29%)
Natural gas (Mcf/day)	271,292	298,503	(9%)	281,393	307,827	(9%)
Total daily sales (BOE/day)	86,209	93,659	(8%)	85,577	95,759	(11%)

As a result of our successful capital development program, we are increasing our annual average production guidance to 84,000 – 86,000 BOE/day from 81,000 – 85,000 BOE/day, and raising the lower end of our crude oil and natural gas liquids guidance range to 39,500 – 41,500 bbls/day from 38,500 – 41,500 bbls/day. This guidance assumes lower third quarter production with the majority of our remaining 2017 North Dakota on-streams scheduled for the fourth quarter, as well as the full impact of divestments completed to date. We are maintaining our fourth quarter exit guidance targets with average production of 86,000 – 91,000 BOE/day and average crude oil and natural gas liquids of 43,000 – 48,000 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 quarterly average prices from the first half of 2017 to the first half of 2016 and other periods indicated:

	Six months ended June 30,						
Pricing (average for the period)	2017	2016	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016
<b>Benchmarks</b>							
WTI crude oil (US\$/bbl)	\$ 50.10	\$ 39.52	\$ 48.29	\$ 51.92	\$ 49.29	\$ 44.94	\$ 45.59
AECO natural gas – monthly index (\$/Mcf)	2.86	1.68	2.77	2.94	2.81	2.20	1.25
AECO natural gas – daily index (\$/Mcf)	2.74	1.62	2.78	2.69	3.09	2.32	1.40
NYMEX natural gas – last day (US\$/Mcf)	3.25	2.02	3.18	3.32	2.98	2.81	1.95
USD/CDN average exchange rate	1.33	1.33	1.34	1.32	1.33	1.31	1.29
USD/CDN period end exchange rate	1.30	1.30	1.30	1.33	1.34	1.31	1.30
<b>Enerplus selling price<sup>(1)</sup></b>							
Crude oil (\$/bbl)	\$ 56.54	\$ 39.00	\$ 55.66	\$ 57.53	\$ 53.91	\$ 47.93	\$ 46.48
Natural gas liquids (\$/bbl)	30.57	13.37	25.14	37.76	21.31	13.85	15.67
Natural gas (\$/Mcf)	3.56	1.64	3.48	3.63	2.89	2.12	1.49
<b>Average differentials</b>							
MSW Edmonton – WTI (US\$/bbl)	\$ (2.90)	\$ (3.39)	\$ (2.26)	\$ (3.54)	\$ (3.11)	\$ (2.96)	\$ (3.09)
WCS Hardisty – WTI (US\$/bbl)	(12.85)	(13.77)	(11.13)	(14.58)	(14.32)	(13.50)	(13.30)
Transco Leidy monthly – NYMEX (US\$/Mcf)	(0.61)	(0.84)	(0.60)	(0.63)	(1.58)	(1.35)	(0.70)
TGP Z4 300L monthly – NYMEX (US\$/Mcf)	(0.68)	(0.90)	(0.66)	(0.70)	(1.64)	(1.40)	(0.73)
AECO monthly – NYMEX (US\$/Mcf)	(1.12)	(0.76)	(1.13)	(1.10)	(0.86)	(1.13)	(0.99)
<b>Enerplus realized differentials <sup>(1)(2)</sup></b>							
Canada crude oil – WTI (US\$/bbl)	\$ (11.95)	\$ (13.46)	\$ (11.02)	\$ (12.76)	\$ (12.97)	\$ (12.06)	\$ (12.01)
Canada natural gas – NYMEX (US\$/Mcf)	(0.56)	(0.74)	(0.51)	(0.56)	(0.63)	(0.92)	(0.86)
Bakken crude oil – WTI (US\$/bbl)	(5.49)	(8.29)	(5.43)	(5.59)	(6.80)	(6.39)	(8.23)
Marcellus natural gas – NYMEX (US\$/Mcf)	(0.62)	(0.83)	(0.64)	(0.60)	(0.88)	(1.19)	(0.76)

(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 during the quarter decreased by 3% to average \$55.66/bbl, compared to a 7% decrease in benchmark WTI prices.

Bakken price differentials to WTI improved by 3% during the quarter to average US\$5.43/bbl below WTI. Spot Bakken prices strengthened considerably late in the second quarter and into the third quarter as the Dakota Access Pipeline was brought into service in early June. However, during the second quarter we had a higher proportion of our crude oil production trucked from new pads brought on-stream which contributed to a wider differential than the spot pricing. Based on the ongoing strength we are seeing in the Bakken market, we continue to expect our Bakken crude oil differential to average US\$4.50/bbl below WTI for 2017.

Our realized price differential for our Canadian crude oil production improved by 14% compared to the previous quarter, due largely to strength in Canadian light and heavy crude oil benchmark prices which were impacted by ongoing regional oil sands production outages. Our realized price for natural gas liquids averaged \$25.14/bbl during the period, a decrease of 33% compared to the previous quarter. Both Canadian and U.S. natural gas liquids prices fell in the second quarter with lower demand.

## NATURAL GAS

Our average realized natural gas price during the second quarter decreased by 4% compared to the first quarter to average \$3.48/Mcf. Benchmark NYMEX natural gas prices also decreased by 4% during the quarter due to higher U.S. gas production.

Our realized Marcellus sales price differential excluding transportation and gathering widened during the quarter to average US\$0.64/Mcf below NYMEX. Benchmark monthly Transco Leidy prices averaged US\$0.60/Mcf below NYMEX during the second quarter. Regulatory concerns announced in May are expected to delay the targeted completion of the construction of the Rover pipeline project that will transport gas from the Marcellus/Utica region into the U.S. Midwest and Eastern Canada. Combined

with higher production in the region relative to the previous quarter, these anticipated delays resulted in weakness in regional basis markets in the Marcellus pushing differentials wider late in the quarter. As a result, we expect our Marcellus natural gas realized price differential to now average US\$0.75/Mcf below NYMEX for 2017. Once Rover and other pipeline projects slated for completion in 2017 are in-service, we expect Marcellus price differentials to improve.

Most of our Canadian gas production is sold under multi-year fixed AECO basis differential contracts at prices higher than those currently realized in the spot market. Our realized Canadian gas price differential averaged US\$0.51/Mcf below NYMEX compared to the AECO benchmark monthly price that averaged US\$1.13/Mcf below NYMEX in the second quarter.

## FOREIGN EXCHANGE

The USD/CDN exchange rate was 1.30 USD/CDN at June 30, 2017, and averaged 1.34 USD/CDN during the second quarter of 2017 compared to average rates of 1.32 USD/CDN during the first quarter of 2017, and USD/CDN 1.29 during the second 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 August 10, 2017, we have hedged 20,000 bbls/day of our expected crude oil production for the remainder of 2017, which represents approximately 72% of our 2017 forecasted crude oil production, after royalties. For 2018, we have hedged 18,000 bbls/day, which represents approximately 65% 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. 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 in any given month, 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 August 10, 2017, we have hedged 50,000 Mcf/day of our forecasted natural gas production for the remainder of 2017. This represents approximately 25% of our forecasted natural gas production, after royalties. Note that all of our NYMEX gas hedges have been transacted using a three way collar structure. When NYMEX prices settle below the sold put strike price in any given month, the three way collars provide a limited amount of protection above the NYMEX settled price 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 August 10, 2017, expressed as a percentage of our forecasted 2017 net production volumes:

	WTI Crude Oil (US\$/bbl) <sup>(1)</sup>					NYMEX Natural Gas (US\$/Mcf) <sup>(1)</sup>
	Jul 1, 2017 – Dec 31, 2017	Jan 1, 2018 – Jun 30, 2018	Jul 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019	Jul 1, 2017 – Dec 31, 2017
<b>Swaps</b>						
Sold Swaps	\$ 53.50	\$ 53.73	\$ 53.73	\$ 53.73	—	—
%	7%	11%	11%	11%	—	—
<b>Three Way Collars</b>						
Sold Puts	\$ 39.62	\$ 42.83	\$ 42.63	\$ 45.00	\$ 43.75	\$ 2.06
%	65%	47%	62%	4%	15%	25%
Purchased Puts	\$ 50.61	\$ 53.04	\$ 52.56	\$ 56.00	\$ 54.69	\$ 2.75
%	65%	47%	62%	4%	15%	25%
Sold Calls	\$ 60.33	\$ 61.99	\$ 61.29	\$ 70.00	\$ 66.18	\$ 3.41
%	65%	47%	62%	4%	15%	25%

(1) Based on weighted average price (before premiums) assuming average annual production of 85,000 BOE/day less royalties and production taxes of 24%.

## ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) (\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Cash gains/(losses):				
Crude oil	\$ 2.2	\$ 16.4	\$ 1.3	\$ 52.9
Natural gas	—	5.2	7.5	8.3
Total cash gains/(losses)	\$ 2.2	\$ 21.6	\$ 8.8	\$ 61.2
Non-cash gains/(losses):				
Crude oil	\$ 27.3	\$ (27.2)	\$ 71.6	\$ (58.4)
Natural gas	2.4	(16.3)	9.1	(11.2)
Total non-cash gains/(losses)	\$ 29.7	\$ (43.5)	\$ 80.7	\$ (69.6)
Total gains/(losses)	\$ 31.9	\$ (21.9)	\$ 89.5	\$ (8.4)

(Per BOE)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Total cash gains/(losses)	\$ 0.28	\$ 2.53	\$ 0.57	\$ 3.51
Total non-cash gains/(losses)	3.79	(5.10)	5.21	(3.99)
Total gains/(losses)	\$ 4.07	\$ (2.57)	\$ 5.78	\$ (0.48)

During the second quarter of 2017 we realized cash gains of \$2.2 million on our crude oil contracts. In comparison, during the second quarter of 2016 we realized cash gains of \$16.4 million on our crude oil contracts and \$5.2 million on our natural gas contracts. The cash gains recorded in the quarter were due to crude oil contracts which provided floor protection above market prices.

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 second quarter of 2017, the fair value of our crude oil contracts was in a net asset position of \$42.8 million, while the fair value of our natural gas contracts was in a net liability position of \$0.4 million. For the three and six months ended June 30, 2017, the change in the fair value of our crude oil contracts represented gains of \$27.3 million and \$71.6 million, respectively, and our natural gas contracts represented gains of \$2.4 million and \$9.1 million, respectively.

## Revenues

(\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Oil and natural gas sales	\$ 282.1	\$ 212.7	\$ 559.8	\$ 383.2
Royalties	(56.4)	(38.4)	(106.3)	(66.2)
Oil and natural gas sales, net of royalties	\$ 225.7	\$ 174.3	\$ 453.5	\$ 317.0

Oil and natural gas sales for the three and six months ended June 30, 2017 were \$282.1 million and \$559.8 million, respectively, an increase of 33% and 46% from the same periods in 2016. The increase in revenue primarily resulted from higher commodity pricing for both oil and natural gas compared to the same periods in 2016, which more than offset the impact of lower production volumes with asset divestments.

## Royalties and Production Taxes

(\$ millions, except per BOE amounts)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Royalties	\$ 56.4	\$ 38.4	\$ 106.3	\$ 66.2
Per BOE	\$ 7.19	\$ 4.51	\$ 6.86	\$ 3.80
Production taxes	\$ 13.8	\$ 8.6	\$ 24.2	\$ 16.0
Per BOE	\$ 1.76	\$ 1.00	\$ 1.56	\$ 0.92
Royalties and production taxes	\$ 70.2	\$ 47.0	\$ 130.5	\$ 82.2
Per BOE	\$ 8.95	\$ 5.51	\$ 8.42	\$ 4.72
Royalties and production taxes (% of oil and natural gas sales)	25%	22%	23%	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 and six months ended June 30, 2017, royalties and production taxes increased to \$70.2 million and \$130.5 million, respectively, from \$47.0 million and \$82.2 million for the same periods in 2016 primarily due to higher commodity prices. In the second quarter of 2017, royalties and production taxes averaged 25% of crude oil and natural gas sales before transportation primarily due to annual provincial royalty adjustments and a greater weighting of our production coming from our U.S. properties with higher overall royalty rates.

We are maintaining our annual average royalty and production tax rate guidance of 24% in 2017.

## Operating Expenses

(\$ millions, except per BOE amounts)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Cash operating expenses	\$ 46.2	\$ 61.4	\$ 96.4	\$ 133.7
Non-cash (gains)/losses <sup>(1)</sup>	(0.4)	(0.9)	(0.3)	(0.6)
Total operating expenses	\$ 45.8	\$ 60.5	\$ 96.1	\$ 133.1
Per BOE	\$ 5.83	\$ 7.10	\$ 6.21	\$ 7.64

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

For the three and six months ended June 30, 2017, operating expenses were \$45.8 million (\$5.83/BOE) and \$96.1 million (\$6.21/BOE), respectively, compared to our annual guidance of \$6.85/BOE. Operating costs are lower by \$14.7 million and \$37.0 million relative to the same respective periods in 2016 and nearly 20% lower on a per BOE basis, mainly due to the divestment of higher operating cost Canadian properties throughout 2016 and into 2017, reduced activity levels, and cost savings initiatives.

As a result, we are lowering our annual guidance for operating expenses to \$6.40/BOE from \$6.85/BOE.

## Transportation Costs

(\$ millions, except per BOE amounts)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Transportation costs	\$ 29.2	\$ 24.5	\$ 58.8	\$ 50.2
Per BOE	\$ 3.72	\$ 2.87	\$ 3.80	\$ 2.88

For the three and six months ended June 30, 2017, transportation costs were \$29.2 million (\$3.72/BOE) and \$58.8 million (\$3.80/BOE), respectively, relative to our annual guidance target of \$4.00/BOE. During the same periods in 2016 transportation costs were \$24.5 million (\$2.87/BOE) and \$50.2 million (\$2.88/BOE). 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, and a higher proportion of U.S. production volumes which have higher associated transportation costs.

We are revising our annual guidance for transportation costs to \$3.90/BOE from \$4.00/BOE due to the impact of lower expected USD/CDN foreign exchange rates on U.S. transportation costs and the increase in our annual average production.

## 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.

Netbacks by Property Type	Three months ended June 30, 2017		
	Crude Oil	Natural Gas	Total
Average Daily Production	44,678 BOE/day	249,180 Mcfe/day	86,209 BOE/day
Netback <sup>(1)</sup> \$ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	\$ 50.22	\$ 3.44	\$ 35.96
Royalties and production taxes	(13.82)	(0.62)	(8.95)
Cash operating expenses	(10.06)	(0.23)	(5.88)
Transportation costs	(2.35)	(0.87)	(3.72)
Netback before hedging	\$ 23.99	\$ 1.72	\$ 17.41
Cash gains/(losses)	0.55	—	0.28
Netback after hedging	\$ 24.54	\$ 1.72	\$ 17.69
Netback before hedging (\$ millions)	\$ 97.5	\$ 39.0	\$ 136.5
Netback after hedging (\$ millions)	\$ 99.7	\$ 39.0	\$ 138.7

Netbacks by Property Type	Three months ended June 30, 2016		
	Crude Oil	Natural Gas	Total
Average Daily Production	46,972 BOE/day	280,122 Mcfe/day	93,659 BOE/day
Netback <sup>(1)</sup> \$ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	\$ 40.57	\$ 1.54	\$ 24.96
Royalties and production taxes	(9.57)	(0.24)	(5.51)
Cash operating expenses	(10.04)	(0.73)	(7.20)
Transportation costs	(1.85)	(0.64)	(2.87)
Netback before hedging	\$ 19.11	\$ (0.07)	\$ 9.38
Cash gains/(losses)	3.83	0.20	2.53
Netback after hedging	\$ 22.94	\$ 0.13	\$ 11.91
Netback before hedging (\$ millions)	\$ 81.6	\$ (1.8)	\$ 79.7
Netback after hedging (\$ millions)	\$ 98.0	\$ 3.4	\$ 101.3

Netbacks by Property Type	Six months ended June 30, 2017		
	Crude Oil	Natural Gas	Total
Average Daily Production	42,546 BOE/day	258,180 Mcfe/day	85,577 BOE/day
Netback <sup>(1)</sup> \$ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	\$ 51.21	\$ 3.54	\$ 36.14
Royalties and production taxes	(13.24)	(0.61)	(8.42)
Cash operating expenses	(10.16)	(0.39)	(6.23)
Transportation costs	(2.42)	(0.86)	(3.80)
Netback before hedging	\$ 25.39	\$ 1.68	\$ 17.69
Cash gains/(losses)	0.17	0.16	0.57
Netback after hedging	\$ 25.56	\$ 1.84	\$ 18.26
Netback before hedging (\$ millions)	\$ 195.6	\$ 78.5	\$ 274.1
Netback after hedging (\$ millions)	\$ 196.8	\$ 86.1	\$ 282.9

Netbacks by Property Type	Six months ended June 30, 2016		
	Crude Oil	Natural Gas	Total
Average Daily Production	47,836 BOE/day	287,538 Mcfe/day	95,759 BOE/day
Netback <sup>(1)</sup> \$ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	\$ 33.82	\$ 1.70	\$ 21.99
Royalties and production taxes	(7.95)	(0.25)	(4.72)
Cash operating expenses	(10.06)	(0.88)	(7.67)
Transportation costs	(1.85)	(0.65)	(2.88)
Netback before hedging	\$ 13.96	\$ (0.08)	\$ 6.72
Cash gains/(losses)	6.08	0.16	3.51
Netback after hedging	\$ 20.04	\$ 0.08	\$ 10.23
Netback before hedging (\$ millions)	\$ 121.5	\$ (4.4)	\$ 117.0
Netback after hedging (\$ millions)	\$ 174.5	\$ 3.8	\$ 178.2

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

Crude oil and natural gas netbacks per BOE were higher for both the three and six months ended June 30, 2017 compared to the same periods in 2016 due to significantly higher oil and natural gas prices, improvements in the sales price differentials in North Dakota and Marcellus regions, along with reductions to our operating expenses, due to the sale of non-core Canadian

natural gas assets. For the three and six month periods ended June 30, 2017, our crude oil properties accounted for 71% of our netback before hedging compared to 100% of our netback during the same periods in 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 11 and Note 14 to the Interim Financial Statements for further details.

(\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Cash:				
G&A expense	\$ 12.0	\$ 14.6	\$ 26.3	\$ 33.0
Share-based compensation expense	—	0.8	0.1	1.5
Non-Cash:				
Share-based compensation expense	3.3	5.4	11.4	8.9
Equity swap loss/(gain)	—	(1.6)	1.0	(1.7)
<b>Total G&amp;A expenses</b>	<b>\$ 15.3</b>	<b>\$ 19.2</b>	<b>\$ 38.8</b>	<b>\$ 41.7</b>

(Per BOE)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Cash:				
G&A expense	\$ 1.53	\$ 1.71	\$ 1.69	\$ 1.89
Share-based compensation expense	—	0.09	0.01	0.09
Non-Cash:				
Share-based compensation expense	0.42	0.63	0.74	0.51
Equity swap loss/(gain)	0.01	(0.18)	0.07	(0.10)
<b>Total G&amp;A expenses</b>	<b>\$ 1.96</b>	<b>\$ 2.25</b>	<b>\$ 2.51</b>	<b>\$ 2.39</b>

For the three and six months ended June 30, 2017, cash G&A expenses were \$12.0 million (\$1.53/BOE) and \$26.3 million (\$1.69/BOE), respectively, compared to \$14.6 million (\$1.71/BOE) and \$33.0 million (\$1.89/BOE) for the same periods in 2016. The decrease in cash G&A expenses from the prior year was primarily due to continued cost savings initiatives and the impact of reductions in staff levels throughout 2016 and early 2017 as we continue to focus our business through asset divestments.

We recorded non-cash SBC of \$3.3 million or \$0.42/BOE in the second quarter of 2017 compared to \$5.4 million or \$0.63/BOE during the same period in 2016, due to a smaller employee base in 2017.

Based on our increased annual average production guidance and continued focus on costs, we are reducing our annual cash G&A guidance to \$1.75/BOE from \$1.85/BOE.

### Interest Expense

For the three and six months ended June 30, 2017, we recorded total interest expense of \$10.2 million and \$20.4 million, respectively, compared to \$10.0 million and \$24.6 million for the same period in 2016. Interest expense was essentially flat when compared to the three months ended June 30, 2016, however decreased for the six months ended June 30, 2017 when compared to the same period in 2016. The decrease for the six month period ended June 30, 2017 was primarily due to the repurchase of US\$267 million of senior notes during the first half of 2016.

At June 30, 2017, we were undrawn on our \$800 million bank credit facility and our debt balance consisted of fixed interest rate senior notes with a weighted average interest rate of 4.8%. See Note 8 in the Interim Financial Statements for further details.

### Foreign Exchange

(\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Realized loss/(gain)	\$ 0.9	\$ 0.3	\$ 1.0	\$ 2.0
Unrealized loss/(gain)	(13.1)	0.1	(17.0)	(56.0)
<b>Total foreign exchange loss/(gain)</b>	<b>\$ (12.2)</b>	<b>\$ 0.4</b>	<b>\$ (16.0)</b>	<b>\$ (54.0)</b>
USD/CDN average exchange rate	1.34	1.29	1.33	1.33
USD/CDN period end exchange rate	1.30	1.30	1.30	1.30

For the three and six months ended June 30, 2017, we recorded net foreign exchange gains of \$12.2 million and \$16.0 million, respectively, compared to a loss of \$0.4 million and a gain of \$54.0 million for the same periods 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 June 30, 2017 to December 31, 2016, the Canadian dollar strengthened relative to the U.S. dollar resulting in unrealized gains of \$17.0 million. See Note 12 to the Interim Financial Statements for further details.

### Capital Investment

(\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Capital spending	\$ 101.7	\$ 48.1	\$ 222.1	\$ 91.4
Office capital	0.3	0.1	0.4	0.1
Sub-total	102.0	48.2	222.5	91.5
Property and land acquisitions	\$ 4.7	\$ 0.3	\$ 7.2	\$ 3.9
Property divestments	(59.8)	(92.7)	(58.9)	(280.5)
Sub-total	(55.1)	(92.4)	(51.7)	(276.6)
Total	\$ 46.9	\$ (44.2)	\$ 170.8	\$ (185.1)

Capital spending for the three and six months ended June 30, 2017, totaled \$101.7 million and \$222.1 million, respectively, compared to \$48.1 million and \$91.4 million for the same period in 2016. The increased spending is in line with our strategy to re-initiate growth through an increased capital program in 2017. During the quarter we spent \$70.7 million on our North Dakota crude oil properties, \$17.5 million on our Marcellus natural gas assets and \$9.9 million on our Canadian waterflood properties.

During the second quarter, we closed a portion of our previously announced Canadian asset divestments for proceeds of \$59.6 million, after closing adjustments, with estimated 2017 production of approximately 5,600 BOE/day, and \$46.9 million in asset retirement obligations. In comparison, during the same period of 2016 we completed the sale of properties in northwest Alberta for proceeds of \$92.7 million, net of closing costs, with estimated 2016 production of 2,300 BOE/day and \$12.7 million in asset retirement obligations.

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

### Gain on Asset Sales and Note Repurchases

We recorded a gain of \$78.4 million on the sale of Canadian properties during the second quarter of 2017. In comparison, we recorded a gain of \$74.7 million on certain asset divestments during the second quarter of 2016. 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.

For the three and six month periods ended June 30, 2016, we recorded gains of \$12.2 million and \$19.3 million on the repurchase of US\$95 million and US\$267 million, respectively, in outstanding senior notes at a discount to par value.

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

(\$ millions, except per BOE amounts)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
DD&A expense	\$ 64.8	\$ 82.9	\$ 125.4	\$ 174.2
Per BOE	\$ 8.26	\$ 9.73	\$ 8.09	\$ 10.00

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and six months ended June 30, 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 with asset divestments.

## 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 half of 2017 compared to a decrease during the same period in 2016. There were no non-cash impairments recorded for the three and six months ended June 30, 2017, compared to \$148.7 million and \$194.9 million recognized in the same periods of 2016.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the amount 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 6 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 \$110.7 million at June 30, 2017, compared to \$181.7 million at December 31, 2016. For the three and six months ended June 30, 2017, asset retirement obligation settlements were \$1.5 million and \$4.1 million, respectively, compared to \$0.8 million and \$3.2 million during the same periods in 2016. As a result of our divestments to date in 2017, we have reduced our asset retirement obligation by \$72.1 million or 40%. See Note 9 to the Interim Financial Statements for further details.

## Income Taxes

(\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Current tax expense/(recovery)	\$ 2.0	\$ (0.2)	\$ 2.1	\$ (0.4)
Deferred tax expenses/(recovery)	38.3	53.3	67.1	309.8
Total tax expense/(recovery)	\$ 40.3	\$ 53.1	\$ 69.2	\$ 309.4

For the three and six months ended June 30, 2017, we recorded total tax expense of \$40.3 million and \$69.2 million, respectively, compared to \$53.1 million and \$309.4 million for the same periods in 2016.

Current tax expense for the three and six months ended June 30, 2017 was \$2.0 million and \$2.1 million, respectively, compared to recoveries of \$0.2 million and \$0.4 million for the same periods in 2016. The increase in current tax expense is primarily due to higher income in the U.S.

Deferred tax expense was higher in both comparative periods due to a valuation allowance recorded in both Canada and the U.S. We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not that all or a portion of our deferred income tax assets will be realized. Our overall net deferred income tax asset was \$648.6 million at June 30, 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 June 30, 2017, our senior debt to adjusted EBITDA ratio was 0.8x and our net debt to adjusted funds flow ratio was 0.7x. 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 June 30, 2017 was \$308.1 million, a decrease of 18% compared to \$375.5 million at December 31, 2016. Total debt was comprised of \$693.1 million of senior notes less \$385.1 million in cash. Proceeds from the December, 2016 sale of our non-operated North Dakota properties were released from escrow on June 29, 2017 and are now being held as cash, without restriction. In June 2017, we made the first of five annual installments of US\$22 million on the remaining principal of the US\$110 million 2009 senior notes. At June 30, 2017, 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 96% and 101% for the three and six months ended June 30, 2017, respectively, compared to 72% and 96% for the same periods in 2016.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, increased to \$104.5 million at June 30, 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 June 30, 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](http://www.sedar.com).

The following table lists our financial covenants as at June 30, 2017:

Covenant Description		June 30, 2017
<b>Bank Credit Facility:</b>		
	<b>Maximum Ratio</b>	
Senior debt to adjusted EBITDA <sup>(1)</sup>	3.5x	0.8x
Total debt to adjusted EBITDA	4.0x	0.8x
Total debt to capitalization	50%	21%
<b>Senior Notes:</b>		
	<b>Maximum Ratio</b>	
Senior debt to adjusted EBITDA <sup>(2)</sup>	3.0x - 3.5x	0.8x
Senior debt to consolidated present value of total proved reserves <sup>(3)</sup>	60%	26%
	<b>Minimum Ratio</b>	
Adjusted EBITDA to interest	4.0 x	20.8x

### 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 June 30, 2017 was \$200.6 million and \$858.2 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 June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Dividends to shareholders	\$ 7.3	\$ 6.5	\$ 14.5	\$ 21.0
Per weighted average share (Basic)	\$ 0.03	\$ 0.03	\$ 0.06	\$ 0.10

During the three and six months ended June 30, 2017, we reported total dividends of \$7.3 million or \$0.03 per share and \$14.5 million or \$0.06 per share, respectively, compared to \$6.5 million or \$0.03 per share and \$21.0 million or \$0.10 per share for the

same periods 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

	Six months ended June 30,	
	2017	2016
Share capital (\$ millions)	\$ 3,386.9	\$ 3,366.0
Common shares outstanding (thousands)	242,129	240,483
Weighted average shares outstanding – basic (thousands)	241,710	212,420
Weighted average shares outstanding – diluted (thousands)	246,566	212,420

During the second quarter, no shares were issued pursuant to our LTI plans, resulting in no additional equity being recorded during the period (2016 – nil). For the six months ended June 30, 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 14 to the Interim Financial Statements.

On May 31, 2016, 33,350,000 common shares were issued at a price of \$6.90 per share for gross proceeds of \$230.1 million (\$220.4 million net of issue costs).

At August 10, 2017, we had 242,128,944 shares outstanding.

## SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

(\$ millions, except per unit amounts)	Three months ended June 30, 2017			Three months ended June 30, 2016		
	Canada	U.S.	Total	Canada	U.S.	Total
<b>Average Daily Production Volumes <sup>(1)</sup></b>						
Crude oil (bbls/day)	10,853	26,008	36,861	13,497	25,582	39,079
Natural gas liquids (bbls/day)	1,199	2,934	4,133	1,418	3,411	4,829
Natural gas (Mcf/day)	46,729	224,563	271,292	79,878	218,625	298,503
Total average daily production (BOE/day)	19,840	66,369	86,209	28,228	65,431	93,659
<b>Pricing <sup>(2)</sup></b>						
Crude oil (per bbl)	\$ 50.45	\$ 57.83	\$ 55.66	\$ 43.27	\$ 48.18	\$ 46.48
Natural gas liquids (per bbl)	37.35	20.14	25.14	25.14	11.74	15.67
Natural gas (per Mcf)	3.59	3.46	3.48	1.41	1.52	1.49
<b>Capital Expenditures</b>						
Capital spending	\$ 10.6	\$ 91.1	\$ 101.7	\$ 7.2	\$ 40.9	\$ 48.1
Acquisitions	1.1	3.6	4.7	1.0	(0.7)	0.3
Divestments	(59.6)	(0.2)	(59.8)	(91.1)	(1.6)	(92.7)
<b>Netback<sup>(3)</sup> Before Hedging</b>						
Oil and natural gas sales	\$ 69.2	\$ 212.9	\$ 282.1	\$ 66.6	\$ 146.1	\$ 212.7
Royalties	(14.3)	(42.1)	(56.4)	(9.7)	(28.7)	(38.4)
Production taxes	(0.8)	(13.0)	(13.8)	(0.1)	(8.5)	(8.6)
Cash operating expenses	(19.4)	(26.8)	(46.2)	(31.4)	(30.0)	(61.4)
Transportation costs	(3.1)	(26.1)	(29.2)	(3.9)	(20.6)	(24.5)
Netback before hedging	\$ 31.6	\$ 104.9	\$ 136.5	\$ 21.5	\$ 58.3	\$ 79.8
<b>Other Expenses</b>						
Commodity derivative instruments loss/(gain)	\$ (31.9)	\$ —	\$ (31.9)	\$ 21.9	\$ —	\$ 21.9
General and administrative expense <sup>(4)</sup>	7.9	7.4	15.3	14.7	4.5	19.2
Current income tax expense/(recovery)	—	2.0	2.0	(0.4)	0.2	(0.2)

(\$ millions, except per unit amounts)	Six months ended June 30, 2017			Six months ended June 30, 2016		
	Canada	U.S.	Total	Canada	U.S.	Total
<b>Average Daily Production Volumes <sup>(1)</sup></b>						
Crude oil (bbls/day)	11,875	23,155	35,030	13,841	25,453	39,294
Natural gas liquids (bbls/day)	1,301	2,347	3,648	1,612	3,549	5,161
Natural gas (Mcf/day)	57,575	223,818	281,393	89,708	218,119	307,827
Total average daily production (BOE/day)	22,772	62,805	85,577	30,404	65,355	95,759
<b>Pricing <sup>(2)</sup></b>						
Crude oil (per bbl)	\$ 51.11	\$ 59.32	\$ 56.54	\$ 34.70	\$ 41.33	\$ 39.00
Natural gas liquids (per bbl)	37.21	26.88	30.57	25.05	8.07	13.37
Natural gas (per Mcf)	3.62	3.54	3.56	1.74	1.59	1.64
<b>Capital Expenditures</b>						
Capital spending	\$ 35.6	\$ 186.5	\$ 222.1	\$ 26.3	\$ 65.1	\$ 91.4
Acquisitions	2.7	4.5	7.2	2.0	1.9	3.9
Divestments	(58.7)	(0.2)	(58.9)	(279.4)	(1.1)	(280.5)
<b>Netback<sup>(3)</sup> Before Hedging</b>						
Oil and natural gas sales	\$ 156.3	\$ 403.5	\$ 559.8	\$ 123.3	\$ 259.9	\$ 383.2
Royalties	(26.2)	(80.1)	(106.3)	(15.1)	(51.1)	(66.2)
Production taxes	(1.9)	(22.3)	(24.2)	(0.9)	(15.1)	(16.0)
Cash operating expenses	(45.9)	(50.5)	(96.4)	(74.9)	(58.8)	(133.7)
Transportation costs	(7.5)	(51.3)	(58.8)	(7.5)	(42.7)	(50.2)
Netback before hedging	\$ 74.8	\$ 199.3	\$ 274.1	\$ 24.9	\$ 92.2	\$ 117.1
<b>Other Expenses</b>						
Commodity derivative instruments loss/(gain)	\$ (89.5)	\$ —	\$ (89.5)	\$ 8.4	\$ —	\$ 8.4
General and administrative expense <sup>(4)</sup>	25.7	13.1	38.8	33.1	8.6	41.7
Current income tax expense/(recovery)	—	2.1	2.1	(0.7)	0.3	(0.4)

(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		Net Income/(Loss) Per Share	
	Sales, Net of Royalties	Net Income/(Loss)	Basic	Diluted
<b>2017</b>				
Second Quarter	\$ 225.7	\$ 129.3	\$ 0.53	\$ 0.52
First Quarter	227.8	76.3	0.32	0.31
Total 2017	\$ 453.5	\$ 205.6	\$ 0.85	\$ 0.83
<b>2016</b>				
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
<b>2015</b>				
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, decreased slightly in the second quarter compared to the first quarter of 2017 due to lower realized commodity prices offset by higher oil and natural gas liquids production volumes. Oil and natural 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.

### U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2017, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

### 2017 UPDATED GUIDANCE

We are increasing our annual average production guidance range to 84,000 – 86,000 BOE/day from 81,000 – 85,000 BOE/day, and increasing the lower end of our crude oil and natural gas liquids volume range to 39,500 – 41,500 BOE/day from 38,500 – 41,500 BOE/day previously. We are reducing our cash costs by \$0.65/BOE, with revised guidance targets for operating expenses of \$6.40/BOE, cash G&A expenses of \$1.75/BOE, and transportation costs of \$3.90/BOE. We are also increasing our expected 2017 average Marcellus differential to US\$0.75/Mcf below NYMEX from US\$0.60/Mcf.

All other guidance targets remain unchanged and are 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	84,000 – 86,000 BOE/day (from 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	39,500 – 41,500 bbls/day (from 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	\$6.40/BOE (from \$6.85/BOE)
Transportation costs	\$3.90/BOE (from \$4.00/BOE)
Cash G&A expenses	\$1.75/BOE (from \$1.85/BOE)

### 2017 Differential/Basis Outlook<sup>(1)</sup>

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\$(0.75)/Mcf (from US\$(0.60)/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 (\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Oil and natural gas sales	\$ 282.1	\$ 212.7	\$ 559.8	\$ 383.2
Less:				
Royalties	(56.4)	(38.4)	(106.3)	(66.2)
Production taxes	(13.8)	(8.6)	(24.2)	(16.0)
Cash operating expenses <sup>(1)</sup>	(46.2)	(61.4)	(96.4)	(133.7)
Transportation costs	(29.2)	(24.5)	(58.8)	(50.2)
Netback before hedging	\$ 136.5	\$ 79.8	\$ 274.1	\$ 117.1
Cash gains/(losses) on derivative instruments	2.2	21.6	8.8	61.2
Netback after hedging	\$ 138.7	\$ 101.4	\$ 282.9	\$ 178.3

(1) Total operating expenses adjusted to exclude non-cash gains on fixed price electricity swaps of \$0.4 million and \$0.3 million in the three and six months ended June 30, 2017, and \$0.9 million and \$0.6 million, respectively, in the three and six months ended June 30, 2016.

“**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 (\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Cash flow from operating activities	\$ 98.3	\$ 61.9	\$ 226.2	\$ 131.6
Asset retirement obligation expenditures	1.5	0.7	4.1	3.2
Changes in non-cash operating working capital	14.4	13.4	3.8	(17.0)
Adjusted funds flow	\$ 114.2	\$ 76.0	\$ 234.1	\$ 117.8

“**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 (\$ millions)	Three months ended June 30,		Six months ended June 30,	
	2017	2016	2017	2016
Dividends	\$ 7.3	\$ 6.5	\$ 14.5	\$ 21.0
Capital and office expenditures	102.0	48.2	222.5	91.5
Sub-total	\$ 109.3	\$ 54.7	\$ 237.0	\$ 112.5
Adjusted funds flow	\$ 114.2	\$ 76.0	\$ 234.1	\$ 117.8
Adjusted payout ratio (%)	96%	72%	101%	96%

“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<sup>(1)</sup>

(\$ millions)	June 30, 2017
Net income/(loss)	\$ 945.2
Add:	
Interest	40.4
Current and deferred tax expense/(recovery)	(477.5)
DD&A and asset impairment	387.2
Other non-cash charges <sup>(2)</sup>	(14.2)
Sub-total	\$ 881.1
Adjustment for material acquisitions and divestments <sup>(3)</sup>	(22.9)
Adjusted EBITDA	\$ 858.2

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at June 30, 2017 include the six months ended June 30, 2017 and the 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”, “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 June 30, 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 April 1, 2017 and ended June 30, 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](http://www.sedar.com), on the EDGAR website at [www.sec.gov](http://www.sec.gov) and at [www.enerplus.com](http://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 prices for the rest of the year: a WTI price of US\$50.00/bbl, a NYMEX price of US\$3.00/Mcf, an AECO price of \$2.40/GJ and a USD/CDN exchange rate of 1.30. 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, 2016).

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.