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

The following discussion and analysis of financial results is dated November 10, 2016 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 nine months ended September 30, 2016 and 2015 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013; and
- our MD&A for the year ended December 31, 2015 (the "Annual MD&A").

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of the MD&A for further information.

BASIS OF PRESENTATION

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

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. BOE and Mcfe measures are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a Company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101– Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities.

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

OVERVIEW

During the third quarter, we continued to improve our profitability through further cost reductions and strong operational results. Based on the success of our ongoing asset divestment program and our second quarter equity issue, we have a strong balance sheet and are repositioned for growth in 2017.

Average daily production for the third quarter was 92,077 BOE/day, compared to our annual average production guidance range of 92,000 – 94,000 BOE/day. Production decreased 2% from the second quarter largely due to the June 2016 sale of non-core Canadian properties with production of approximately 2,300 BOE/day. The decrease in Canadian volumes was offset by strong performance in the U.S., where production increased 3% compared to the second quarter. We are reaffirming our 2016 annual average production guidance of 93,000 BOE/day, the mid-point of our previous guidance range, with approximately 43,000 – 44,000 bbls/day of crude oil and natural gas liquids.

Our capital spending for the third quarter was $60.3 million, or $151.7 million year to date, with the majority directed to our North Dakota crude oil properties. We are maintaining our 2016 annual capital spending guidance of $215 million.

Operating expenses for the third quarter came in below guidance of $7.90/BOE, totaling $56.2 million or $6.64/BOE. The decrease in operating costs was mainly due to continued improvement in cost structures, reduced activity levels and the ongoing divestment of higher cost Canadian properties. As a result, we are reducing our annual guidance for operating expenses to $7.50/BOE from $7.90/BOE. Cash G&A expenses were also below guidance, totaling $13.4 million or $1.58/BOE compared to guidance of $1.95/BOE, primarily due to the continued reduction in staff levels and ongoing cost saving efforts. Accordingly, we are revising our annual cash G&A expense guidance to $1.80/BOE from $1.95/BOE.

Our commodity hedging program continued to provide funds flow protection, contributing cash gains of $10.0 million in the third quarter. Since the second quarter, we have increased our downside protection. As of November 1, 2016, we have approximately 56% of our forecasted crude oil production, net of royalties, hedged in 2017 and approximately 12% of our forecasted net crude oil production hedged in 2018 and the first quarter of 2019. We have also hedged approximately 22% of our forecasted natural gas production, net of royalties, in 2017.

We recorded funds flow of $80.1 million and a net loss of $100.7 million for the quarter. Third quarter earnings were impacted by a non-cash impairment charge of $61.0 million and a non-cash valuation allowance on our deferred tax asset as a result of the decline in the twelve month trailing average commodity prices.

Our asset divestment program and proceeds from our second quarter equity issuance have allowed us to reduce our debt levels by 46% year to date, strengthening our balance sheet and improving our financial flexibility. Subsequent to the quarter, we entered into an agreement to acquire a Canadian waterflood property with current production of approximately 3,800 BOE/day, which we expect to close in November, for consideration of approximately $110 million, net of anticipated closing adjustments.

2017 PRELIMINARY OUTLOOK

As a result of our improving cost structures and strong capital efficiencies, we plan to accelerate our crude oil growth in 2017 with a capital spending program of approximately $400 million. The majority of our capital spending will be focused on our North Dakota crude oil properties, where we have secured a second drilling rig commencing operations in January 2017. We expect this capital spending to result in meaningful liquids growth, with a 15% increase in crude oil and liquids volumes from the fourth quarter of 2016 to the fourth quarter of 2017, and a 25% increase in North Dakota production over the same period. At US$50/bbl WTI and US$3.00/Mcf NYMEX, we expect our capital spending program and dividends to be approximately balanced with internally generated cash flow. Based on the expected increase in liquids production, we estimate our 2017 operating expenses will be approximately $8.00/BOE.

We expect to provide further details of our 2017 guidance in late 2016.

RESULTS OF OPERATIONS

Production

Average daily production for the third quarter totaled 92,077 BOE/day, in line with our expectations. Compared to production in the second quarter of 2016 of 93,659 BOE/day, production decreased 2% primarily due to the June 2016 sale of non-core Canadian assets with production of approximately 2,300 BOE/day. Lower Canadian volumes were offset by higher U.S. production, which increased 3% as a result of strong performance in Marcellus and North Dakota.

Production in the third quarter of 2016 decreased 17% from production levels of 110,794 BOE/day in the same period of 2015 primarily due to the sale of non-core properties from the fourth quarter of 2015 to date in 2016 with production of approximately 11,800 BOE/day. Natural gas production decreased 68,195 Mcf/day or 19% compared to the third quarter of 2015, with a 48% decrease in Canadian natural gas volumes due to divestments, price related shut-ins and decline due to lower overall spending. This reduction was offset by strong Marcellus production, which decreased only 2% despite lower capital spending. Crude oil and liquids production decreased 15% over the same period primarily due to fewer wells coming on-stream in North Dakota during the third quarter of 2016 compared to the same period in 2015, as well as divestments and lower capital spending in 2016.

Our crude oil and natural gas liquids production accounted for 46% of our total average daily production in the third quarter of 2016 compared to 45% in the same period of 2015 as a significant portion of divestments were non-core Canadian natural gas assets.

Average daily production volumes for the three and nine months ended September 30, 2016 and 2015 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2016**	**2015**	**% Change**	**2016**	**2015**	**% Change**
Crude oil (bbls/day)	37,717	44,888	(16%)	38,764	41,809	(7%)
Natural gas liquids (bbls/day)	4,881	5,061	(4%)	5,067	4,652	9%
Natural gas (Mcf/day)	296,876	365,071	(19%)	304,150	359,611	(15%)
Total daily sales (BOE/day)	92,077	110,794	(17%)	94,523	106,396	(11%)

We are reaffirming our annual average production guidance of 93,000 BOE/day, the mid-point of our previous guidance range of 92,000 – 94,000 BOE/day. We are revising our crude oil and natural gas liquids production guidance to 43,000 – 44,000 bbls/day, from 43,000 – 45,000 bbls/day, primarily due to weather related delays to completions activity in North Dakota. We continue to expect fourth quarter production of 89,000 BOE/day. Volumes in the fourth quarter are expected to be impacted by approximately 1,500 BOE/day of curtailed production in the Marcellus due to low natural gas prices and a 1,000 BOE/day decrease in Canadian gas production as a result of price related shut-ins and minor third quarter asset divestments. These reductions are expected to be offset by strong North Dakota production and the Canadian waterflood acquisition, with a projected closing date of November 2016.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares average prices for the nine months ended September 30, 2016 and 2015 and quarterly average prices for other periods indicated:

	Nine months ended September 30,						
Pricing (average for the period)	**2016**	**2015**	**Q3 2016**	**Q2 2016**	**Q1 2016**	**Q4 2015**	**Q3 2015**
Benchmarks							
WTI crude oil (US$/bbl)	$ 41.33	$ 51.00	$ 44.94	$ 45.59	$ 33.45	$ 42.18	$ 46.43
AECO natural gas – monthly index ($/Mcf)	1.85	2.80	2.20	1.25	2.11	2.65	2.80
AECO natural gas – daily index ($/Mcf)	1.85	2.77	2.32	1.40	1.83	2.47	2.90
NYMEX natural gas – last day (US$/Mcf)	2.29	2.80	2.81	1.95	2.09	2.27	2.77
USD/CDN average exchange rate	1.32	1.26	1.31	1.29	1.37	1.34	1.31
USD/CDN period end exchange rate	1.31	1.34	1.31	1.30	1.30	1.38	1.34
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 41.92	$ 50.21	$ 47.93	$ 46.48	$ 31.59	$ 43.04	$ 48.22
Natural gas liquids ($/bbl)	13.53	18.60	13.85	15.67	11.34	16.61	13.51
Natural gas ($/Mcf)	1.79	2.24	2.12	1.49	1.77	1.89	2.08
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (3.24)	$ (4.43)	$ (2.96)	$ (3.09)	$ (3.69)	$ (2.44)	$ (3.42)
WCS Hardisty – WTI (US$/bbl)	(13.68)	(13.20)	(13.50)	(13.30)	(14.24)	(14.50)	(13.27)
Transco Leidy monthly – NYMEX (US$/Mcf)	(1.01)	(1.64)	(1.35)	(0.70)	(0.99)	(1.15)	(1.66)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(1.07)	(1.69)	(1.40)	(0.73)	(1.07)	(1.23)	(1.75)
AECO monthly – NYMEX (US$/Mcf)	(0.89)	(0.57)	(1.13)	(0.99)	(0.56)	(0.28)	(0.63)
Enerplus realized differentials (1)							
Canada crude oil – WTI (US$/bbl)	$ (13.17)	$ (13.33)	$ (12.06)	$ (12.01)	$ (14.14)	$ (13.63)	$ (11.82)
Canada natural gas – NYMEX (US$/Mcf)	(0.81)	(0.45)	(0.92)	(0.86)	(0.63)	(0.42)	(0.43)
Bakken crude oil – WTI (US$/bbl)	(7.63)	(9.84)	(6.39)	(8.23)	(8.38)	(7.93)	(8.52)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.94)	(1.46)	(1.19)	(0.76)	(0.91)	(1.13)	(1.64)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Our average realized crude oil price during the period was $47.93/bbl, an increase of 3% compared to the prior quarter despite the benchmark WTI price declining slightly. This was due primarily to the continued narrowing of the differentials for our U.S. crude oil production. Declining regional production and strong local refinery demand resulted in our Bakken differential improving by 22% quarter over quarter to average US$6.39/bbl below WTI for the third quarter. Canadian crude oil prices and differentials were essentially flat compared to the second quarter. Our third quarter realized natural gas liquids price fell by 12% compared to the second quarter, in-line with the changes in benchmark liquids prices over the same period.

NATURAL GAS

Our average realized natural gas price during the third quarter was $2.12/Mcf, 42% higher when compared to the prior quarter due to much stronger U.S. and Canadian benchmark prices but offset slightly by seasonally weaker Marcellus differentials. NYMEX and AECO monthly natural gas prices in the quarter improved by 44% and 76%, respectively compared to the previous quarter as very warm weather in the U.S. increased gas demand at a time when U.S. gas production continued to decline.

A significant portion of our Canadian gas production is sold under fixed AECO basis differential contracts. In the third quarter our realized Canadian gas price differential was 7% wider than in the second quarter, averaging US$0.92/Mcf below NYMEX, however the AECO monthly differential benchmark price widened by 14% over the same period.

As expected, our third quarter realized Marcellus sales price differential was weaker than the previous quarter, averaging US$1.19/Mcf below NYMEX or 57% wider than the second quarter. This was due to high regional storage inventories combined with unplanned pipeline restrictions. In August, we began transporting an incremental 15% of our Marcellus production out of the region to markets in the southern United States. This long-term firm transportation commitment allows us to access a market that trades closer to the NYMEX price. We estimate this pipeline capacity has improved our overall Marcellus realized price differential by approximately US$0.13/Mcf since the beginning of August.

FOREIGN EXCHANGE

The USD/CDN exchange rate was 1.31 USD/CDN at September 30, 2016, and averaged 1.31 USD/CDN during the third quarter compared to 1.29 USD/CDN during the second quarter. 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, the economics of our capital program and potential acquisitions. Since our second quarter, we have added additional floor protection on a portion of our oil and natural gas production extending to the first quarter of 2019 using both three way collars and swaps.

As of November 1, 2016, we have hedged approximately 13,300 bbls/day of our expected crude oil production for the remainder of 2016, which represents approximately 43% of our forecasted 2016 net crude oil production, after royalties. For 2017, we have hedged 17,500 bbls/day, which represents approximately 56% of our forecasted net crude oil production, after royalties. We have also added hedges for 2018 and the first quarter of 2019 to protect the economics of a portion of our capital program. When WTI prices settle below the sold put strike price in any given month, the three way collars provide protection above the WTI index prices 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 November 1, 2016, we have hedged approximately 50,000 Mcf/day of our forecasted natural gas production for the remainder of 2016. This represents approximately 26% of our forecasted natural gas production, after royalties. For 2017, we have hedged 50,000 Mcf/day, which represents approximately 22% of our forecasted net natural gas production, using three way collars. When NYMEX prices settle below the sold put strike price in any given month, the three way collars provide protection above the NYMEX index 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 November 1, 2016, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[1]					NYMEX Natural Gas (US$/Mcf)[1]	
	Oct 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Jun 30, 2017	Jul 1, 2017 – Dec 31, 2017	Jan 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Oct 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017
Swaps							
Sold Swaps	$ 52.33	$ 52.50	$ 52.50	$ 53.73	$ 53.73	$ 2.51	$ —
%	4%	6%	6%	10%	10%	15%	—
Three Way Collars							
Sold Puts	$ 45.09	$ 38.94	$ 39.48	$ 41.00	$ —	$ 2.50	$ 2.06
%	39%	45%	55%	3%	—	11%	22%
Purchased Puts	$ 57.82	$ 50.29	$ 50.41	$ 54.00	$ —	$ 3.00	$ 2.75
%	39%	45%	55%	3%	—	11%	22%
Sold Calls	$ 71.75	$ 61.14	$ 60.41	$ 62.00	$ —	$ 3.75	$ 3.41
%	39%	45%	55%	3%	—	11%	22%

(2) Based on weighted average price (before premiums) assuming average annual production of 93,000 BOE/day less royalties and production taxes of 22%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2016	2015	2016	2015
Cash gains/(losses):				
Crude oil	$ 11.1	$ 36.6	$ 64.0	$ 163.8
Natural gas	(1.1)	17.5	7.1	50.2
Total cash gains/(losses)	$ 10.0	$ 54.1	$ 71.1	$ 214.0
Non-cash gains/(losses):				
Crude oil	$ (1.7)	$ 35.1	$ (60.1)	$ (71.9)
Natural gas	3.8	(8.2)	(7.4)	(30.4)
Total non-cash gains/(losses)	$ 2.1	$ 26.9	$ (67.5)	$ (102.3)
Total gains/(losses)	$ 12.1	$ 81.0	$ 3.6	$ 111.7

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2016	2015	2016	2015
Total cash gains/(losses)	$ 1.17	$ 5.31	$ 2.75	$ 7.36
Total non-cash gains/(losses)	0.25	2.64	(2.61)	(3.52)
Total gains/(losses)	$ 1.42	$ 7.95	$ 0.14	$ 3.84

During the third quarter of 2016 we realized cash gains of $11.1 million on our crude oil contracts and cash losses of $1.1 million on our natural gas contracts. In comparison, during the third quarter of 2015 we realized cash gains of $36.6 million on our crude oil contracts and $17.5 million on our natural gas contracts. The cash gains were due to contracts which provided floor protection above market prices, while cash losses were a result of prices rising above our fixed swap positions.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the third quarter of 2016, the fair value of our crude oil contracts was in a net gain position of $7.3 million, while the fair value of our natural gas contracts was in a net loss position of $3.4 million. For the three and nine months ended September 30, 2016, the change in the fair value of our crude oil contracts resulted in losses of $1.7 million and $60.1 million, respectively, and our natural gas contracts resulted in gains of $3.8 million and losses of $7.4 million, respectively.

Revenues

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2016	2015	2016	2015
Oil and natural gas sales	$ 230.4	$ 275.7	$ 613.6	$ 818.2
Royalties	(42.1)	(47.4)	(108.3)	(133.2)
Oil and natural gas sales, net of royalties	$ 188.3	$ 228.3	$ 505.3	$ 685.0

Oil and natural gas sales for the three and nine months ended September 30, 2016 were $230.4 million and $613.6 million, respectively, a decrease of 16% and 25% from the same periods in 2015. The decrease in revenue during the third quarter was primarily a result of lower production volumes compared to the same period in 2015, while the nine month period was impacted by both a decrease in production and lower oil and natural gas prices compared to the same period in 2015.

Royalties and Production Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	**2016**	**2015**	**2016**	**2015**
Royalties	$ 42.1	$ 47.4	$ 108.3	$ 133.2
Per BOE	$ 4.97	$ 4.65	$ 4.18	$ 4.59
Production taxes	$ 10.4	$ 13.9	$ 26.4	$ 38.9
Per BOE	$ 1.23	$ 1.36	$ 1.02	$ 1.34
Royalties and production taxes	$ 52.5	$ 61.3	$ 134.7	$ 172.1
Per BOE	$ 6.20	$ 6.01	$ 5.20	$ 5.93
Royalties and production taxes (% of oil and natural gas sales)	23%	22%	22%	21%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. A large percentage of our production is from U.S. properties where royalty rates are generally less sensitive to commodity price levels. During the three and nine months ended September 30, 2016, royalties and production taxes decreased to $52.5 million and $134.7 million, respectively, from $61.3 million and $172.1 million for the same periods in 2015, primarily due to lower production volumes, along with lower prices over the nine month period. Royalties and production taxes averaged 22% of oil and natural gas sales before transportation costs in the first nine months of 2016 compared to 21% for the same period in 2015 due to a greater portion of our production coming from our U.S. properties, which have an average combined royalty and production tax rate of approximately 25%.

We continue to expect an average royalty and production tax rate of 22% in 2016. We do not expect the Alberta modernized royalty framework to have a significant impact on our Canadian royalties.

Operating Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	**2016**	**2015**	**2016**	**2015**
Cash operating expenses	$ 56.2	$ 88.6	$ 189.9	$ 254.8
Non-cash (gains)/losses(1)	—	1.8	(0.5)	0.1
Total operating expenses	$ 56.2	$ 90.4	$ 189.4	$ 254.9
Per BOE	$ 6.64	$ 8.87	$ 7.31	$ 8.77

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

For the three and nine months ended September 30, 2016, operating expenses were $56.2 million and $189.4 million, respectively, a decrease of 38% and 26% compared to the same periods in 2015. On a per BOE basis, operating costs for the three and nine months ended September 30, 2016 were $6.64/BOE and $7.31/BOE, respectively, beating our annual guidance of $7.90/BOE. The decrease in operating costs was mainly a result of our continued cost savings in repairs and maintenance and well servicing and the divestment of higher operating cost Canadian properties in the fourth quarter of 2015 and throughout 2016.

Based on cost improvements to date, we are lowering our 2016 guidance for operating expenses to $7.50/BOE from $7.90/BOE. Although our operating costs were below guidance during the third quarter, we expect fourth quarter expenses to increase on a per BOE basis due to lower fourth quarter production and a higher liquids weighting.

Transportation Costs

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	**2016**	**2015**	**2016**	**2015**
Transportation costs	$ 28.8	$ 30.9	$ 78.9	$ 85.4
Per BOE	$ 3.39	$ 3.03	$ 3.05	$ 2.94

For the three and nine months ended September 30, 2016, transportation costs were $28.8 million ($3.39/BOE) and $78.9 million ($3.05/BOE), respectively, compared to $30.9 million ($3.03/BOE) and $85.4 million ($2.94/BOE) for the same periods in 2015.

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 at pricing of US$0.63/Mcf, plus variable costs, that came into effect in August 2016.

We are updating our 2016 guidance for transportation costs to $3.15/BOE from $3.10/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 September 30, 2016		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	46,471 BOE/day	273,636 Mcfe/day	92,077 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 40.69	$ 2.24	$ 27.20
Royalties and production taxes	(10.22)	(0.35)	(6.20)
Cash operating expenses	(10.29)	(0.48)	(6.64)
Transportation costs	(2.20)	(0.77)	(3.39)
Netback before hedging	$ 17.98	$ 0.64	$ 10.97
Cash gains/(losses)	2.59	(0.04)	1.17
Netback after hedging	$ 20.57	$ 0.60	$ 12.14
Netback before hedging ($ millions)	$ 76.9	$ 16.0	$ 92.9
Netback after hedging ($ millions)	$ 88.0	$ 14.9	$ 102.9

	Three months ended September 30, 2015		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	52,764 BOE/day	348,180 Mcfe/day	110,794 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 43.34	$ 2.04	$ 27.04
Royalties and production taxes	(11.02)	(0.24)	(6.01)
Cash operating expenses	(11.48)	(1.03)	(8.69)
Transportation costs	(1.74)	(0.70)	(3.03)
Netback before hedging	$ 19.10	$ 0.07	$ 9.31
Cash gains/(losses)	7.53	0.55	5.31
Netback after hedging	$ 26.63	$ 0.62	$ 14.62
Netback before hedging ($ millions)	$ 92.7	$ 2.2	$ 94.9
Netback after hedging ($ millions)	$ 129.2	$ 19.8	$ 149.0

	Nine months ended September 30, 2016		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	47,403 BOE/day	282,720 Mcfe/day	94,523 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 36.07	$ 1.87	$ 23.69
Royalties and production taxes	(8.55)	(0.30)	(5.20)
Cash operating expenses	(10.27)	(0.73)	(7.33)
Transportation costs	(1.96)	(0.69)	(3.05)
Netback before hedging	$ 15.29	$ 0.15	$ 8.11
Cash gains/(losses)	4.93	0.09	2.75
Netback after hedging	$ 20.22	$ 0.24	$ 10.86
Netback before hedging ($ millions)	$ 198.6	$ 11.5	$ 210.1
Netback after hedging ($ millions)	$ 262.6	$ 18.6	$ 281.2

Netbacks by Property Type	Nine months ended September 30, 2015 Crude Oil	Natural Gas	Total
Average Daily Production	48,930 BOE/day	344,796 Mcfe/day	106,396 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 45.62	$ 2.22	$ 28.17
Royalties and production taxes	(10.99)	(0.27)	(5.93)
Cash operating expenses	(11.99)	(1.00)	(8.77)
Transportation costs	(1.79)	(0.65)	(2.94)
Netback before hedging	$ 20.85	$ 0.30	$ 10.53
Cash gains/(losses)	12.26	0.53	7.36
Netback after hedging	$ 33.11	$ 0.83	$ 17.89
Netback before hedging ($ millions)	$ 278.4	$ 27.5	$ 305.9
Netback after hedging ($ millions)	$ 442.2	$ 77.7	$ 519.9

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

Crude oil and natural gas netbacks per BOE after hedging were lower for the three and nine months ended September 30, 2016 compared to the same periods in 2015 primarily due to lower realized hedging gains, offset by significant improvements in our operating costs. Our crude oil properties accounted for the majority of our netback, both before and after hedging.

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”) and our stock option plan. See Note 10 and Note 14 to the Interim Financial Statements for further details.

($ millions)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Cash:				
G&A expense	$ 13.4	$ 22.8	$ 46.4	$ 64.1
Share-based compensation expense	0.2	(3.6)	1.8	2.5
Non-Cash:				
Share-based compensation expense	2.9	7.8	11.7	17.4
Equity swap loss/(gain)	0.1	2.0	(1.6)	1.4
Total G&A expenses	$ 16.6	$ 29.0	$ 58.3	$ 85.4

(Per BOE)	Three months ended September 30, 2016	2015	Nine months ended September 30, 2016	2015
Cash:				
G&A expense	$ 1.58	$ 2.24	$ 1.79	$ 2.21
Share-based compensation expense	0.03	(0.35)	0.07	0.08
Non-Cash:				
Share-based compensation expense	0.35	0.77	0.45	0.60
Equity swap loss/(gain)	0.01	0.19	(0.06)	0.05
Total G&A expenses	$ 1.97	$ 2.85	$ 2.25	$ 2.94

For the three and nine months ended September 30, 2016, cash G&A expenses were $13.4 million ($1.58/BOE) and $46.4 million ($1.79/BOE), respectively, compared to $22.8 million ($2.24/BOE) and $64.1 million ($2.21/BOE) for the same periods in 2015. The decrease in cash G&A expenses from the prior year was primarily due to a 35% reduction in staff levels throughout 2015 and to date in 2016, offset by one-time severance payments of $4.1 million in 2016, as we continue to divest non-core properties and focus our business.

During the quarter, we reported cash SBC expense of $0.2 million ($0.03/BOE) with minimal movement in our share price. In comparison, during the same period of 2015, our share price decreased 41% resulting in a recovery of $3.6 million ($0.35/BOE). We recorded non-cash SBC of $2.9 million ($0.35/BOE) in the third quarter of 2016 compared to $7.8 million ($0.77/BOE) during the same period in 2015. The decrease in non-cash SBC was due to reduced staffing levels.

We have hedged a portion of the outstanding cash settled grants under our LTI plans. In the third quarter we recorded a non-cash mark-to-market loss of $0.1 million on these hedges. As of September 30, 2016 we had 470,000 units hedged at a weighted average price of $16.89 per share.

Based on our continued focus on costs, we are reducing our 2016 guidance for cash G&A expenses to $1.80/BOE from $1.95/BOE.

Interest Expense

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2016	2015	2016	2015
Interest on senior notes and bank facility	$ 9.7	$ 16.3	$ 34.3	$ 48.9
Non-cash interest expense	0.2	0.2	0.9	0.8
Total interest expense	$ 9.9	$ 16.5	$ 35.2	$ 49.7

For the three and nine months ended September 30, 2016, we recorded total interest expense of $9.9 million and $35.2 million, respectively, compared to $16.5 million and $49.7 million for the same periods in 2015. The decrease in interest expense corresponds to a decrease in the aggregate principal amount of our outstanding senior notes following our repurchase of US$267 million of senior notes during the first half of 2016. The repurchase was funded by asset divestment proceeds and lower interest rate bank debt, which was repaid in full following our May 31, 2016 equity financing and the closing of our second quarter Canadian non-core asset divestment.

At September 30, 2016, our $800 million bank credit facility was undrawn, and our debt balance consisted of fixed interest rate senior notes with a weighted average interest rate of 5.0%.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2016	2015	2016	2015
Realized loss/(gain)	$ (0.9)	$ 8.8	$ 1.1	$ (18.4)
Unrealized loss/(gain)	4.0	60.8	(52.0)	164.6
Total foreign exchange loss/(gain)	$ 3.1	$ 69.6	$ (50.9)	$ 146.2
USD/CDN average exchange rate	1.31	1.31	1.32	1.26

For the three and nine months ended September 30, 2016, we recorded a net foreign exchange loss of $3.1 million and a net foreign exchange gain of $50.9 million, respectively, compared to a loss of $69.6 million and a loss of $146.2 million for the same periods in 2015. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies. During the nine months ended September 30, 2015, we recorded realized gains of $18.4 million primarily due to a $39.9 million gain on the unwind of certain foreign exchange swaps offset by losses on our foreign exchange collars.

Unrealized foreign exchange gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing September 30, 2016 to December 31, 2015, the Canadian dollar strengthened relative to the U.S. dollar and we reduced our U.S. dollar denominated senior notes by 33% resulting in unrealized gains of $52.0 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2016	2015	2016	2015
Capital spending	$ 60.3	$ 88.9	$ 151.7	$ 403.9
Office capital	0.6	1.0	0.7	3.3
Sub-total	60.9	89.9	152.4	407.2
Property and land acquisitions	$ 3.8	$ 2.0	$ 7.7	$ 0.8
Property divestments	(0.1)	(11.9)	(280.6)	(203.4)
Sub-total	3.7	(9.9)	(272.9)	(202.6)
Total	$ 64.6	$ 80.0	$ (120.5)	$ 204.6

Capital spending for the three and nine months ended September 30, 2016, totaled $60.3 million and $151.7 million, respectively, compared to $88.9 million and $403.9 million for the same periods in 2015. The decrease is in line with our reduced spending program for 2016, as we continue to invest modestly in our core areas. During the third quarter we spent $45.1 million on our North Dakota crude oil properties, $8.0 million on our Canadian crude oil properties and $7.2 million on our Marcellus natural gas assets.

During the third quarter of 2016 we completed minor asset divestments for proceeds of approximately $0.6 million with associated natural gas production of approximately 400 BOE/day. In comparison, we disposed of non-core Canadian oil properties for proceeds of $11.9 million with production of 150 BOE/day in the same period of 2015. Year to date, we have recorded total proceeds on asset divestments of $280.6 million, compared to $203.4 million in the same period of 2015.

Subsequent to the quarter, we entered into an agreement to acquire a Canadian waterflood property with current production of approximately 3,800 BOE/day for $110 million, net of anticipated closing adjustments. We expect the acquisition to close in November 2016.

We continue to expect 2016 annual capital spending of $215 million.

Gain on Asset Sales and Note Repurchases

We recorded gains of $219.8 million on the sale of non-core Canadian properties during the first half 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. We did not record any gains or losses on asset divestments during the third quarter of 2016.

During the first half of 2016, we recorded a total gain of $19.3 million on the repurchase of US$267 million of outstanding senior notes at prices between 90% of par and par value.

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2016	2015	2016	2015
DD&A expense	$ 91.6	$ 131.5	$ 265.1	$ 401.3
Per BOE	$ 10.81	$ 12.90	$ 10.23	$ 13.81

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 nine months ended September 30, 2016, DD&A decreased when compared the same periods of 2015 primarily due to the cumulative effects of asset impairments recorded during 2015 and to date in 2016 as well as lower overall production.

Impairment

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

The trailing twelve month average crude oil and natural gas prices continued to decline in the first three quarters of 2016 but less significantly than in 2015. Non-cash impairments of $61.0 million and $255.8 million were recorded for the three and nine months ended September 30, 2016, respectively, compared to $321.2 million and $1,086.0 million in the same periods of 2015.

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the remainder of this year, 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 below current levels, there is the potential for prices to decline further during the final months of 2016, impacting the ceiling value and resulting in further non-cash impairments. See Note 5 to the Interim Financial Statements for trailing twelve month prices.

Asset Retirement Obligation

In connection with our operations we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on our net ownership interest and management's estimate of costs to abandon and reclaim and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation to be $185.8 million at September 30, 2016, compared to $206.4 million at December 31, 2015. For the three and nine months ended September 30, 2016, asset retirement obligation settlements were $1.2 million and $4.4 million, respectively, compared to

$4.2 million and $10.6 million during the same periods in 2015. As a result of our divestments to date in 2016, we have reduced our asset retirement obligation by $28.3 million.

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2016	2015	2016	2015
Current tax expense/(recovery)	$ 0.1	$ (16.2)	$ (0.3)	$ (16.2)
Deferred tax expenses/(recovery)	23.2	(84.9)	333.0	(445.0)
Total tax expense/(recovery)	$ 23.3	$ (101.1)	$ 332.7	$ (461.2)

For the three and nine months ended September 30, 2016 we recorded total tax expense of $23.3 million and $332.7 million, respectively, compared to a tax recovery of $101.1 million and $461.2 million for the same periods in 2015. The current quarter expense includes an additional valuation allowance of $56.6 million recorded against our deferred income tax asset, partially offset by a recovery due to the non-cash asset impairment expense recorded in the U.S. and Canada. 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 assessment is primarily based on a projection of undiscounted future taxable income using historical trailing twelve month benchmark prices. After recording the valuation allowance, our overall net deferred income tax asset was $164.0 million at September 30, 2016 compared to $516.1 million at December 31, 2015.

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 September 30, 2016, our senior debt to adjusted EBITDA ratio was 1.3x and our debt to funds flow ratio was 2.2x. Although it is not included in our debt covenants, the debt to funds flow ratio is often used by investors and analysts to evaluate our liquidity.

Total debt net of cash at September 30, 2016 was $654.1 million, a decrease of 46% compared to $1,216.2 million at December 31, 2015. At September 30, 2016, we had $729.1 million of senior notes outstanding less $75.0 million in cash and our $800 million bank credit facility was undrawn.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by funds flow, was 85% and 91% for the three and nine months ended September 30, 2016, compared to 100% and 132% for the same periods in 2015. After adjusting for net acquisition and divestment proceeds, we had a funding surplus of $290.9 million for the nine months ended September 30, 2016.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, increased slightly to $107.5 million at September 30, 2016 from $104.0 million at December 31, 2015. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, 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.

We have continued to be diligent in managing and preserving our financial position. On May 31, 2016, we completed an equity financing for 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million, net of issue costs). Our non-core asset divestment program has provided significant liquidity in 2016, with proceeds of approximately $280.6 million to date in 2016. These proceeds have been used in part to fully repay our drawn credit facility and fund the repurchase of US$267 million of senior notes at prices ranging from 90% of par to par value.

Subsequent to the quarter, we completed a one year extension of our $800 million senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2019. There were no other amendments to the agreement terms or debt covenants. Drawn fees on the facility range between 150 and 315 basis points over Banker’s Acceptance rates, with current drawn fees of 170 basis points over Banker’s Acceptance rates based on our last reported senior debt to adjusted EBITDA ratio. The bank credit facility ranks equally with our senior, unsecured covenant-based notes.

At September 30, 2016, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at September 30, 2016:

Covenant Description		September 30, 2016
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.3x
Total debt to adjusted EBITDA	4.0x	1.3x
Total debt to capitalization	50%	30%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (2)	3.0x - 3.5x	1.3x
Senior debt to consolidated present value of total proved reserves(3)	60%	32%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0 x	11.2x

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 September 30, 2016 were $89.9 million and $582.3 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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per share amounts)	2016	2015	2016	2015
Dividends to shareholders	$ 7.2	$ 30.9	$ 28.2	$ 109.2
Per weighted average share (Basic)	$ 0.03	$ 0.15	$ 0.13	$ 0.53

During the three and nine months ended September 30, 2016, we reported total dividends of $7.2 million or $0.03 per share and $28.2 million or $0.13 per share, respectively, compared to $30.9 million or $0.15 per share and $109.2 million or $0.53 per share for the same periods in 2015.

Effective with the April 2016 payment, we reduced the monthly dividend from $0.03 per share to $0.01 per share to provide additional financial flexibility and to balance funds flow with capital and dividends. The dividend is an important part of our strategy to create shareholder value and we will continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Nine months ended September 30,	
	2016	2015
Share capital ($ millions)	$ 3,366.0	$ 3,132.9
Common shares outstanding (thousands)	240,483	206,496
Weighted average shares outstanding – basic (thousands)	221,843	206,100
Weighted average shares outstanding – diluted (thousands)	221,843	206,100

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).

During the third quarter no shares were issued pursuant to the stock option plan and the treasury settled LTI plans, resulting in no additional equity for the company (2015 – 272,000; $6.4 million). For the nine months ended September 30, 2016 a total of 594,000 shares were issued pursuant to the treasury settled Restricted Share Unit plan resulting in $9.4 million of additional equity (2015 – 764,000; $12.7 million). For further details see Note 14 to the Interim Financial Statements.

At November 10, 2016 we had 240,482,928 shares outstanding.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended September 30, 2016			Three months ended September 30, 2015		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes [1]						
Crude oil (bbls/day)	12,273	25,444	37,717	14,478	30,410	44,888
Natural gas liquids (bbls/day)	1,254	3,627	4,881	1,731	3,330	5,061
Natural gas (Mcf/day)	68,605	228,271	296,876	131,644	233,427	365,071
Total average daily production (BOE/day)	24,961	67,116	92,077	38,150	72,644	110,794
Pricing [2]						
Crude oil (per bbl)	$ 42.92	$ 50.35	$ 47.93	$ 45.31	$ 49.60	$ 48.22
Natural gas liquids (per bbl)	25.67	9.77	13.85	25.31	7.37	13.51
Natural gas (per Mcf)	2.47	2.01	2.12	3.07	1.53	2.08
Capital Expenditures						
Capital spending	$ 8.0	$ 52.3	$ 60.3	$ 29.4	$ 59.5	$ 88.9
Acquisitions	1.2	2.6	3.8	0.9	1.1	2.0
Divestments	—	(0.1)	(0.1)	(11.8)	(0.1)	(11.9)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 67.0	$ 163.4	$ 230.4	$ 101.8	$ 173.9	$ 275.7
Royalties	(9.6)	(32.5)	(42.1)	(11.8)	(35.6)	(47.4)
Production taxes	(1.2)	(9.2)	(10.4)	(1.3)	(12.6)	(13.9)
Cash operating expenses	(30.1)	(26.1)	(56.2)	(55.9)	(32.7)	(88.6)
Transportation costs	(3.3)	(25.5)	(28.8)	(5.4)	(25.5)	(30.9)
Netback before hedging	$ 22.8	$ 70.1	$ 92.9	$ 27.4	$ 67.5	$ 94.9
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (12.1)	$ —	$ (12.1)	$ (81.0)	$ —	$ (81.0)
General and administrative expense [4]	9.8	6.8	16.6	23.9	5.1	29.0
Current income tax expense/(recovery)	—	0.1	0.1	—	(16.2)	(16.2)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See “Non-GAAP Measures” section in this MD&A.
(4) Includes share-based compensation.

($ millions, except per unit amounts)	Nine months ended September 30, 2016 Canada	U.S.	Total	Nine months ended September 30, 2015 Canada	U.S.	Total
Average Daily Production Volumes [1]						
Crude oil (bbls/day)	13,315	25,449	38,764	15,629	26,180	41,809
Natural gas liquids (bbls/day)	1,491	3,576	5,067	2,073	2,579	4,652
Natural gas (Mcf/day)	82,623	221,527	304,150	137,270	222,341	359,611
Total average daily production (BOE/day)	28,577	65,946	94,523	40,580	65,816	106,396
Pricing [2]						
Crude oil (per bbl)	$ 37.24	$ 44.36	$ 41.92	$ 47.41	$ 51.89	$ 50.21
Natural gas liquids (per bbl)	25.22	8.65	13.53	29.59	9.77	18.60
Natural gas (per Mcf)	1.94	1.74	1.79	2.95	1.80	2.24
Capital Expenditures						
Capital spending	$ 34.2	$ 117.5	$ 151.7	$ 131.0	$ 272.9	$ 403.9
Acquisitions	3.2	4.5	7.7	2.9	(2.1)	0.8
Divestments	(279.5)	(1.1)	(280.6)	(199.9)	(3.5)	(203.4)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 190.3	$ 423.3	$ 613.6	$ 330.4	$ 487.8	$ 818.2
Royalties	(24.8)	(83.5)	(108.3)	(35.8)	(97.4)	(133.2)
Production taxes	(2.1)	(24.3)	(26.4)	(4.0)	(34.9)	(38.9)
Cash operating expenses	(105.0)	(84.9)	(189.9)	(162.3)	(92.5)	(254.8)
Transportation costs	(10.8)	(68.1)	(78.9)	(17.4)	(68.0)	(85.4)
Netback before hedging	$ 47.6	$ 162.5	$ 210.1	$ 110.9	$ 195.0	$ 305.9
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (3.6)	$ —	$ (3.6)	$ (111.7)	$ —	$ (111.7)
General and administrative expense [4]	42.9	15.4	58.3	66.6	18.8	85.4
Current income tax expense/(recovery)	(0.7)	0.4	(0.3)	(0.4)	(15.8)	(16.2)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.
(4) Includes share-based compensation.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Diluted
2016				
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	$ 505.3	$ (442.9)	$ (2.00)	$ (2.00)
2015				
Fourth Quarter	$ 199.4	$ (625.0)	$ (3.03)	$ (3.03)
Third Quarter	228.3	(292.7)	(1.42)	(1.42)
Second Quarter	251.7	(312.5)	(1.52)	(1.52)
First Quarter	205.0	(293.2)	(1.42)	(1.42)
Total 2015	$ 884.4	$ (1,523.4)	$ (7.39)	$ (7.39)
2014				
Fourth Quarter	$ 325.3	$ 151.7	$ 0.74	$ 0.73
Third Quarter	378.3	67.4	0.33	0.32
Second Quarter	414.9	40.0	0.20	0.19
First Quarter	407.7	40.0	$ 0.20	0.19
Total 2014	$ 1,526.2	$ 299.1	$ 1.46	$ 1.44

Oil and natural gas sales, net of royalties, increased marginally in the third quarter compared to the second quarter of 2016 due to higher realized crude oil and natural gas prices partially offset by lower oil and gas production volumes. Oil and gas sales, net of royalties, increased during the first half of 2014, then 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.

2016 UPDATED GUIDANCE

We are reaffirming our annual average production guidance of 93,000 BOE/day, the midpoint of the previous guidance range. We are also revising our crude oil and natural gas liquids volumes range, operating expenses, cash G&A expenses and transportation costs. All other guidance has been maintained and is summarized below. This guidance includes the third quarter sale of non-core natural gas properties and the acquisition of a Canadian waterflood property which is expected to close in November 2016, but does not include any additional acquisitions or divestments.

Summary of 2016 Expectations	Target
Capital spending	$215 million
Average annual production	93,000 BOE/day (from 92,000 – 94,000 BOE/day)
Crude oil and natural gas liquids volumes	43,000 – 44,000 bbls/day (from 43,000 – 45,000 bbls/day)
Average royalty and production tax rate (% of oil and natural gas sales)	22%
Operating expenses	$7.50/BOE (from $7.90/BOE)
Transportation costs	$3.15/BOE (from $3.10/BOE)
Cash G&A expenses	$1.80/BOE (from $1.95/BOE)

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 September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Oil and natural gas sales	$ 230.4	$ 275.7	$ 613.6	$ 818.2
Less:				
Royalties	(42.1)	(47.4)	(108.3)	(133.2)
Production taxes	(10.4)	(13.9)	(26.4)	(38.9)
Cash operating expenses[1]	(56.2)	(88.6)	(189.9)	(254.8)
Transportation costs	(28.8)	(30.9)	(78.9)	(85.4)
Netback before hedging	$ 92.9	$ 94.9	$ 210.1	$ 305.9
Cash gains/(losses) on derivative instruments	10.0	54.1	71.1	214.0
Netback after hedging	$ 102.9	$ 149.0	$ 281.2	$ 519.9

(1) Total operating expenses adjusted to exclude non-cash gains on fixed price electricity swaps of nil and $0.5 million in the three and nine months ended September 30, 2016 and non-cash losses of $1.8 million and $0.1 million in the three and nine months ended September 30, 2015.

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

Reconciliation of Cash Flow from Operating Activities to Funds Flow ($ millions)	Three months ended September 30, 2016	Three months ended September 30, 2015	Nine months ended September 30, 2016	Nine months ended September 30, 2015
Cash flow from operating activities	$ 105.9	$ 122.6	$ 237.6	$ 388.8
Asset retirement obligation expenditures	1.2	4.2	4.4	10.6
Changes in non-cash operating working capital	(27.0)	(6.0)	(44.1)	(9.0)
Funds flow	$ 80.1	$ 120.8	$ 197.9	$ 390.4

"**Debt to Funds Flow Ratio**" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The debt to funds flow ratio is calculated as total debt net of cash divided by a trailing twelve months of 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 funds flow.

Calculation of Adjusted Payout Ratio ($ millions)	**Three months ended September 30, 2016**	**2015**	**Nine months ended September 30, 2016**	**2015**
Dividends	$ 7.2	$ 30.9	$ 28.2	$ 109.2
Capital and office expenditures	60.9	89.9	152.4	407.2
Sub-total	$ 68.1	$ 120.8	$ 180.6	$ 516.4
Funds flow	$ 80.1	$ 120.8	$ 197.9	$ 390.4
Adjusted payout ratio (%)	85%	100%	91%	132%

In addition, the Company uses certain financial measures within the “Liquidity and Capital Resources” section 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”, “senior debt to consolidated present value of total proven 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.

Reconciliation of Net Income to Adjusted EBITDA[(1)] ($ millions)	**September 30, 2016**
Net income/(loss)	$ (1,067.9)
Add:	
Interest expense	52.9
Current and deferred tax expense/(recovery)	626.5
DD&A and asset impairment charges	893.3
Other non-cash charges[(2)]	89.0
Sub-total	$ 593.8
Adjustment for material acquisitions and divestments[(3)]	(11.5)
Adjusted EBITDA	$ 582.3

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at September 30, 2016 include the nine months ended September 30, 2016 and the fourth quarters of 2015.
(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.

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 September 30, 2016, 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 July 1, 2016 and ended September 30, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("forward-looking information"). The use of any of the words "expect", "anticipate", "continue", "estimate", “guidance”, "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", “budget”, "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this

MD&A contains forward-looking information pertaining to the following: expected 2016 and 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 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 programs in 2016 and 2017; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2016 and 2017 and its impact on our production level and land holdings; potential future asset and goodwill impairments, as well as the 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 cash taxes; our deferred income taxes; future debt and working capital levels and debt to funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; 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 divestments, expected timing thereof, production and reductions in asset retirement obligations associated therewith and use of proceeds therefrom; expected gains for accounting purposes in respect to our repurchase of senior notes and our asset divestments; anticipated amount of interest expense savings in respect to our repurchase of senior notes; and the amount of future cash dividends that we may pay to our shareholders.

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in 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 funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our funds flow and availability under our bank credit facility to fund our working capital deficiency; 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 2016 guidance contained in this MD&A is based on the following October forward prices: a WTI price of US$53.07/bbl, a NYMEX price of US$3.40/Mcf, an AECO price of $3.01/GJ and a USD/CDN exchange rate of 1.31. Our 2017 guidance contained in this MD&A is based on the following prices: a WTI price of US$50/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.95/GJ and a USD/CDN exchange rate of 1.30. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further decline of commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in the annual MD&A and in our other public filings).

The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.