Exhibit 99.1

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

The following discussion and analysis of financial results is dated November 7, 2019 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and nine months ended September 30, 2019 and 2018 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2018 and 2017 and for the years ended December 31, 2018, 2017 and 2016; and
- our MD&A for the year ended December 31, 2018 (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 thereto have been prepared in accordance with U.S. GAAP, including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included in the Interim Financial Statements. Certain prior period amounts have been restated to conform with current period presentation.

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

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

Effective January 1, 2019, Enerplus adopted ASC 842 - Leases. The most significant impact was the recognition of right-of-use ("ROU") assets and lease liabilities on the Condensed Consolidated Balance Sheet for operating leases and additional note disclosures. See Notes 3(a) and 10 to the Interim Financial Statements for further details.

OVERVIEW

Production for the third quarter averaged 107,181 BOE/day, an increase of 6% compared to second quarter production of 100,694 BOE/day. Crude oil and natural gas liquids production increased by 14% from the second quarter to 60,121 bbls/day with 8.1 net wells brought on stream in North Dakota and the full quarter impact of wells brought on stream near the end of the second quarter. We are narrowing our average annual production guidance range to 100,000 to 101,000 BOE/day from 99,000 to 102,000 BOE/day and narrowing our average annual crude oil and natural gas liquids guidance range to 54,250 to 54,750 bbls/day from 54,000 to 55,500 bbls/day. We are also providing additional fourth quarter average production guidance of 103,000 to 107,000 BOE/day and fourth quarter crude oil and natural gas liquids production guidance of 58,000 to 60,000 bbls/day.

During the third quarter, capital expenditures totaled $151.5 million, with approximately 90% of capital spending directed to U.S. crude oil properties in North Dakota and the DJ Basin. We expect total 2019 annual capital spending of $625 million, compared to the previous guidance range of $610 to $630 million. Capital activity for the remainder of the year will largely be focused on drilling in North Dakota.

Operating expenses and cash General & Administrative ("G&A") expenses were in line with the prior quarter, at $69.6 million and $11.7 million, respectively. As a result of production growth, operating and G&A expenses decreased on a per BOE basis to $7.06/BOE and $1.19/BOE, respectively, compared to $7.84/BOE and $1.26/BOE, respectively, during the second quarter of 2019. We are maintaining our annual operating expense guidance of $7.90/BOE and reducing our annual cash G&A expense guidance to $1.40/BOE from $1.45/BOE.

Our Bakken crude oil price differential widened to US$3.61/bbl below WTI during the third quarter, compared to US$3.00/bbl below WTI in the second quarter of 2019, due to increasing production in the region. Accordingly, we are revising our full year U.S. Bakken crude oil differential outlook to US$3.60/bbl from US$3.25/bbl below WTI. We continue to expect a full year Marcellus natural gas sales price differential of US$0.35/Mcf below NYMEX.

As of November 6, 2019, we had approximately 66% of forecasted crude oil production, net of royalties, hedged for 2019, and approximately 43% of crude oil production, net of royalties, hedged in 2020, based on 2019 forecasted net production.

We reported net income of $65.2 million in the third quarter of 2019 compared to $85.1 million in the second quarter of 2019. The decrease was primarily the result of fluctuations in the USD/CDN foreign exchange rate, which resulted in a $7.1 million foreign exchange loss in the third quarter compared to a gain of $12.3 million in the second quarter of 2019.

During the third quarter of 2019, cash flow from operations decreased to $159.8 million, compared to $237.0 million in the second quarter of 2019, due to changes in working capital, most notably, the receipt of the first Alternative Minimum Tax ("AMT") refund of $57.2 million in the second quarter of 2019. Adjusted funds flow in the third quarter decreased to $175.3 million from $186.0 million in the second quarter of 2019, primarily due to a current tax recovery of $13.9 million recorded in the second quarter.

During the quarter, we repurchased and cancelled 7,145,070 common shares under our Normal Course Issuer Bid ("NCIB") for total consideration of $64.8 million.

At September 30, 2019, total debt net of cash was $521.4 million and our net debt to adjusted funds flow ratio was 0.7x.

RESULTS OF OPERATIONS

Production

Average daily production for the third quarter totaled 107,181 BOE/day, an increase of 6,487 BOE/day or 6% compared to second quarter production of 100,694 BOE/day. Crude oil and natural gas liquids production increased by 7,260 bbls/day or 14% from the second quarter to 60,121 bbls/day. We continued to see oil and natural gas liquids production growth in North Dakota, with 8.1 net wells coming on stream in the third quarter and a full quarter of production from the 24.7 net wells brought on stream in the second quarter. This was partially offset by the sale of certain Canadian assets with associated production of approximately 350 bbls/day in the second quarter. Natural gas production decreased 2% to 282,360 Mcf/day in the third quarter from 287,000 Mcf/day in the second quarter as a result of fewer wells brought on stream during the third quarter.

For the three and nine months ended September 30, 2019, total production increased by 10,320 BOE/day or 11%, and 7,237 BOE/day or 8%, respectively, when compared to the same periods in 2018. Production increased primarily due to our capital program in North Dakota and the DJ Basin, along with strong well performance in the Marcellus.

Our crude oil and natural gas liquids weighting increased to 56% in the third quarter of 2019 from 52% in the second quarter of 2019 and 55% in the third quarter of 2018.

Average daily production volumes for the three and nine months ended September 30, 2019 and 2018 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2019**	**2018**	**% Change**	**2019**	**2018**	**% Change**
Crude oil (bbls/day)	55,023	48,867	13%	48,141	43,892	10%
Natural gas liquids (bbls/day)	5,098	4,563	12%	4,736	4,487	6%
Natural gas (Mcf/day)	282,360	260,591	8%	276,063	259,629	6%
Total daily sales (BOE/day)	107,181	96,861	11%	98,888	91,651	8%

We are narrowing our average annual production guidance range to 100,000 to 101,000 BOE/day from 99,000 to 102,000 BOE/day and are narrowing our average annual crude oil and natural gas liquids guidance range to 54,250 to 54,750 bbls/day from 54,000 to 55,500 bbls/day. In addition, we expect fourth quarter average production of 103,000 to 107,000 BOE/day, including average crude oil and natural gas liquids production of 58,000 to 60,000 bbls/day.

Pricing

The prices received for crude oil and natural gas production directly impact our earnings, cash flow from operations, adjusted funds flow and financial condition. The following table compares quarterly average prices for the nine months ended September 30, 2019 and 2018 and other periods indicated:

	Nine months ended September 30,						
Pricing (average for the period)	**2019**	**2018**	**Q3 2019**	**Q2 2019**	**Q1 2019**	**Q4 2018**	**Q3 2018**
Benchmarks							
WTI crude oil (US$/bbl)	$ 57.06	$ 66.75	$ 56.45	$ 59.81	$ 54.90	$ 58.81	$ 69.50
Brent (ICE) crude oil (US$/bbl)	64.74	72.68	62.00	68.32	63.90	68.08	75.97
NYMEX natural gas – last day (US$/Mcf)	2.67	2.90	2.23	2.64	3.15	3.64	2.90
USD/CDN average exchange rate	1.33	1.29	1.32	1.34	1.33	1.32	1.31
USD/CDN period end exchange rate	1.32	1.29	1.32	1.31	1.33	1.36	1.29
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 69.64	$ 78.58	$ 67.76	$ 74.42	$ 66.56	$ 64.18	$ 83.98
Natural gas liquids ($/bbl)	13.97	28.85	5.97	17.96	19.15	26.72	25.95
Natural gas ($/Mcf)	3.00	3.14	2.13	2.63	4.38	4.28	3.22
Average differentials							
Bakken DAPL – WTI (US$/bbl)	$ (2.75)	$ (1.90)	$ (2.97)	$ (2.36)	$ (2.93)	$ (9.22)	$ (0.97)
Brent (ICE) – WTI (US$/bbl)	7.68	5.93	5.55	8.51	9.00	9.27	6.47
MSW Edmonton – WTI (US$/bbl)	(4.71)	(6.06)	(4.66)	(4.63)	(4.85)	(26.30)	(6.83)
WCS Hardisty – WTI (US$/bbl)	(11.73)	(21.93)	(12.24)	(10.67)	(12.29)	(39.43)	(22.25)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.38)	(0.73)	(0.48)	(0.43)	(0.22)	(0.39)	(0.61)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.34	0.93	(0.35)	(0.31)	1.67	0.20	(0.12)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI (US$/bbl)	$ (3.30)	$ (3.03)	$ (3.61)	$ (3.00)	$ (3.25)	$ (5.60)	$ (2.54)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.31)	(0.46)	(0.44)	(0.57)	0.13	(0.34)	(0.48)
Canada crude oil – WTI (US$/bbl)	(11.28)	(17.86)	(13.50)	(9.99)	(10.42)	(33.27)	(16.61)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Our realized crude oil sales price for the third quarter of 2019 averaged $67.76/bbl, a decrease of 9% compared to the second quarter of 2019. The decrease exceeded the change in WTI pricing, which was due to weakening Bakken and Canadian crude price differentials during the third quarter. Our realized Bakken crude oil differential weakened by US$0.61/bbl during the quarter to average US$3.61/bbl below WTI with increased production in the region pressuring in-basin pricing. Our Bakken sales price consists of a combination of in-basin monthly spot and index sales, term physical sales with fixed differential pricing versus WTI and/or Brent, and sales at the U.S. Gulf Coast delivered via firm capacity on the Dakota Access Pipeline. Bakken differentials began to weaken late in the third quarter and into the fourth quarter due to weaker Brent and WTI differentials in the Gulf Coast, as well as weaker spot prices resulting from higher than expected regional production growth in North Dakota. For the remainder of 2019, we have physical sales contracts in place for an average of 24,800 bbls/day of North Dakota crude oil production with fixed differentials averaging approximately US$2.69/bbl below WTI. Based on year to date price realizations and wider than expected fourth quarter Bakken differentials, we are revising our full year Bakken crude oil differential guidance to US$3.60/bbl below WTI from US$3.25/bbl.

Our realized price differential for Canadian crude oil production widened by US$3.51/bbl compared to the previous quarter, in response to a reduction in the production curtailments imposed by the Alberta government. We have fixed differential financial hedges in place for 1,500 bbls/day of Canadian heavy crude oil production at an average differential of US$14.83/bbl below WTI for the remainder of 2019.

Our realized price for natural gas liquids averaged $5.97/bbl during the third quarter, an $11.99/bbl decrease compared to the second quarter. Liquids pricing weakened further during the quarter as both local and North American butane and propane markets continue to remain oversupplied in 2019.

NATURAL GAS

Our average realized natural gas price during the third quarter of 2019 decreased by 19% compared to the second quarter of 2019 to average $2.13/Mcf, while NYMEX benchmark pricing decreased by 16%. Our realized Marcellus sales differential averaged US$0.44/Mcf below NYMEX during the third quarter. Pricing in U.S. Northeast markets was relatively weak during the quarter, particularly in September, after a cooler than normal summer allowed more gas to be injected into storage. Based on year to date realizations and our fourth quarter pricing outlook, we are maintaining our full year differential guidance for the Marcellus of US$0.35/Mcf below NYMEX.

FOREIGN EXCHANGE

Our oil and natural gas sales are impacted by foreign exchange fluctuations as the majority of our sales are based on U.S. dollar denominated benchmark indices. A weaker Canadian dollar increases the amount of our realized sales, as well as the amount of our U.S. denominated costs, such as capital, interest on our U.S. denominated debt, and the value of our outstanding U.S. senior notes.

The Canadian dollar was weaker during the first nine months of 2019 with an average exchange rate of 1.33 USD/CDN compared to 1.29 USD/CDN for the same period in 2018. However, when compared to the exchange rate of 1.36 USD/CDN at December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, closing the third quarter at 1.32 USD/CDN.

Price Risk Management

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

As of November 6, 2019, we have hedged 24,500 bbls/day of crude oil, which represents approximately 66% of our forecasted crude oil production, after royalties, for the remainder of 2019. For 2020, we have hedged 16,000 bbls/day, which represents approximately 43% of crude oil production, after royalties, based on our 2019 forecast. Our crude oil hedges in 2019 are all three-way collars which consist of a sold put, a purchased put and a sold call. Our crude oil hedges in 2020 are all put spreads with no cap on upside participation. With both three-way collars and put spreads, if WTI prices settle below the sold put strike price, these positions 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 cash flow from operating activities and adjusted funds flow.

We have entered into offsetting purchase transactions on our NYMEX natural gas hedges through October 2019. This has effectively locked in gains of US$0.51/Mcf on our original NYMEX hedges through this term.

The following is a summary of our financial contracts in place at November 6, 2019, expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)(1)	
	Oct 1, 2019 – Dec 31, 2019	**Jan 1, 2020 – Dec 31, 2020**
Three Way Collars(2)		
Sold Puts	$ 44.64	—
%	66%	—
Purchased Puts	$ 54.81	—
%	66%	—
Sold Calls	$ 65.99	—
%	66%	—
Put Spreads(2)		
Sold Puts	—	$ 46.88
%	—	43%
Purchased Puts	—	$ 57.50
%	—	43%

(1) Based on weighted average price (before premiums) assuming average annual production of 100,500 BOE/day, which is the mid-point of our annual 2019 guidance, less royalties and production taxes of 25%. A portion of the sold puts are settled annually rather than monthly.

(2) The total average deferred premium on outstanding hedges is US$2.14/bbl from October 1, 2019 to December 31, 2020.

	NYMEX Natural Gas (US$/Mcf)[1]
	Oct 1, 2019 – Oct 31, 2019
Swaps	
Sold Swaps	$2.85
%	44%
Purchased Swaps	$2.34
%	44%

(1) Based on weighted average price (before premiums) assuming average annual production of 100,500 BOE/day, which is the mid-point of our annual 2019 guidance, less royalties and production taxes of 25%.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Cash gains/(losses):				
Crude oil	$ (2.5)	$ (24.3)	$ (10.4)	$ (50.7)
Natural gas	7.7	0.4	25.0	17.7
Total cash gains/(losses)	$ 5.2	$ (23.9)	$ 14.6	$ (33.0)
Non-cash gains/(losses):				
Crude oil	$ 20.5	$ (30.0)	$ (42.8)	$ (130.8)
Natural gas	(5.5)	(0.2)	(9.1)	(1.7)
Total non-cash gains/(losses)	$ 15.0	$ (30.2)	$ (51.9)	$ (132.5)
Total gains/(losses)	$ 20.2	$ (54.1)	$ (37.3)	$ (165.5)

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2019	2018	2019	2018
Total cash gains/(losses)	$ 0.53	$ (2.68)	$ 0.54	$ (1.32)
Total non-cash gains/(losses)	1.52	(3.39)	(1.93)	(5.29)
Total gains/(losses)	$ 2.05	$ (6.07)	$ (1.39)	$ (6.61)

During the third quarter of 2019, we realized cash losses of $2.5 million on crude oil contracts and cash gains of $7.7 million on natural gas contracts. In comparison, during the third quarter of 2018, we realized cash losses of $24.3 million on crude oil contracts and cash gains of $0.4 million on natural gas contracts. Cash losses in the third quarter of 2019 on crude oil contracts were primarily due to premiums paid on expiring three-way collars. For the same period, cash gains on natural gas contracts resulted from natural gas prices falling below the swap level.

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 September 30, 2019, the fair value of crude oil contracts was in a net asset position of $37.7 million and the fair value of our natural gas contracts was in a net asset position of $1.9 million. For the three and nine months ended September 30, 2019, the change in the fair value of our crude oil contracts resulted in a gain of $20.5 million and a loss of $42.8 million, respectively, and our natural gas contracts resulted in a loss of $5.5 million and $9.1 million, respectively.

Revenues

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Oil and natural gas sales	$ 401.8	$ 466.4	$ 1,161.4	$ 1,201.8
Royalties	(82.9)	(92.8)	(233.6)	(235.8)
Oil and natural gas sales, net of royalties	$ 318.9	$ 373.6	$ 927.8	$ 966.0

Oil and natural gas sales, net of royalties, for the three and nine months ended September 30, 2019, were $318.9 million and $927.8 million, respectively, a decrease of 15% and 4% from the same periods in 2018. The decrease in revenue during the three and nine months ended September 30, 2019 was a result of lower commodity prices, partially offset by higher production compared to the same periods in 2018.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Royalties	$ 82.9	$ 92.8	$ 233.6	$ 235.8
Per BOE	$ 8.41	$ 10.41	$ 8.65	$ 9.42
Production taxes	$ 23.6	$ 26.6	$ 59.6	$ 65.4
Per BOE	$ 2.39	$ 2.98	$ 2.21	$ 2.61
Royalties and production taxes	$ 106.5	$ 119.4	$ 293.2	$ 301.2
Per BOE	$ 10.80	$ 13.39	$ 10.86	$ 12.03
Royalties and production taxes (% of oil and natural gas sales)	27%	26%	25%	25%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees and freehold mineral taxes. A large percentage of our production is from U.S. properties where royalty rates are generally higher than in Canada and less sensitive to commodity price levels. During the three and nine months ended September 30, 2019, royalties and production taxes decreased to $106.5 million and $293.2 million, respectively, from $119.4 million and $301.2 million for the same periods in 2018, primarily due to lower U.S. crude oil revenue.

We are maintaining our annual average royalty and production tax rate guidance of 25% for 2019.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Cash operating expenses	$ 69.6	$ 60.6	$ 211.3	$ 175.3
Non-cash (gains)/losses(1)	—	0.1	—	—
Total operating expenses	$ 69.6	$ 60.7	$ 211.3	$ 175.3
Per BOE	$ 7.06	$ 6.81	$ 7.83	$ 7.01

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

For the three and nine months ended September 30, 2019, operating expenses were $69.6 million or $7.06/BOE and $211.3 million or $7.83/BOE, respectively, representing an increase of $8.9 million and $36.0 million from the same periods in 2018. The increase is mainly attributable to higher North Dakota crude oil and natural gas liquids volumes, higher gas facility charges and well service activity in 2019.

We are maintaining our annual operating cost guidance of $7.90/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Transportation costs	$ 39.0	$ 33.0	$ 107.1	$ 90.1
Per BOE	$ 3.96	$ 3.70	$ 3.97	$ 3.60

For the three and nine months ended September 30, 2019, transportation costs were $39.0 million or $3.96/BOE and $107.1 million or $3.97/BOE, respectively. During the same periods in 2018, transportation costs were $33.0 million or $3.70/BOE and $90.1 million or $3.60/BOE. The increase is due to U.S. production growth and additional crude oil firm transportation commitments that commenced on March 1, 2019 and provide access to sell a portion of our North Dakota production at U.S. Gulf Coast or Brent pricing.

We are maintaining our annual guidance for transportation costs of $4.00/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, 2019		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	64,455 BOE/day	256,356 Mcfe/day	107,181 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 58.69	$ 2.28	$ 40.75
Royalties and production taxes	(16.26)	(0.43)	(10.80)
Cash operating expenses	(10.70)	(0.26)	(7.06)
Transportation costs	(3.13)	(0.87)	(3.96)
Netback before hedging	$ 28.60	$ 0.72	$ 18.93
Cash hedging gains/(losses)	(0.42)	0.33	0.53
Netback after hedging	$ 28.18	$ 1.05	$ 19.46
Netback before hedging ($ millions)	$ 169.7	$ 17.0	$ 186.7
Netback after hedging ($ millions)	$ 167.2	$ 24.7	$ 191.9

	Three months ended September 30, 2018		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	57,244 BOE/day	237,702 Mcfe/day	96,861 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 75.33	$ 3.19	$ 52.32
Royalties and production taxes	(20.16)	(0.60)	(13.39)
Cash operating expenses	(10.05)	(0.35)	(6.80)
Transportation costs	(2.50)	(0.91)	(3.70)
Netback before hedging	$ 42.62	$ 1.33	$ 28.43
Cash hedging gains/(losses)	(4.60)	0.02	(2.68)
Netback after hedging	$ 38.02	$ 1.35	$ 25.75
Netback before hedging ($ millions)	$ 224.5	$ 28.9	$ 253.4
Netback after hedging ($ millions)	$ 200.2	$ 29.3	$ 229.5

	Nine months ended September 30, 2019		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	56,705 BOE/day	253,097 Mcfe/day	98,888 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 61.13	$ 3.11	$ 43.02
Royalties and production taxes	(16.29)	(0.59)	(10.86)
Cash operating expenses	(12.24)	(0.32)	(7.83)
Transportation costs	(2.98)	(0.88)	(3.97)
Netback before hedging	$ 29.62	$ 1.32	$ 20.36
Cash hedging gains/(losses)	(0.67)	0.36	0.54
Netback after hedging	$ 28.95	$ 1.68	$ 20.90
Netback before hedging ($ millions)	$ 458.4	$ 91.4	$ 549.8
Netback after hedging ($ millions)	$ 448.0	$ 116.4	$ 564.4

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

Netbacks by Property Type	Nine months ended September 30, 2018 Crude Oil	Natural Gas	Total
Average Daily Production	51,623 BOE/day	240,168 Mcfe/day	91,651 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 70.67	$ 3.14	$ 48.03
Royalties and production taxes	(18.63)	(0.59)	(12.03)
Cash operating expenses	(10.65)	(0.39)	(7.01)
Transportation costs	(2.35)	(0.87)	(3.60)
Netback before hedging	$ 39.04	$ 1.29	$ 25.39
Cash hedging gains/(losses)	(3.60)	0.27	(1.32)
Netback after hedging	$ 35.44	$ 1.56	$ 24.07
Netback before hedging ($ millions)	$ 550.1	$ 85.1	$ 635.2
Netback after hedging ($ millions)	$ 499.4	$ 102.8	$ 602.2

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

Total netbacks before hedging for the three and nine months ended September 30, 2019 were lower compared to the same periods in 2018 primarily due to weaker realized prices, increased cash operating expenses and increased transportation.

For the three and nine months ended September 30, 2019, our crude oil properties accounted for 91% and 83% of our total netback before hedging, respectively, compared to 89% and 87% during the same periods in 2018.

General and Administrative (“G&A”) Expenses

Total G&A expenses include share-based compensation (“SBC”) charges related to our long-term incentive plans (“LTI plans”). See Note 12 and Note 15 to the Interim Financial Statements for further details.

($ millions)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Cash:				
G&A expense	$ 11.7	$ 12.0	$ 35.5	$ 37.3
Share-based compensation expense	0.1	(0.2)	0.8	2.2
Non-Cash:				
Share-based compensation expense	4.7	4.3	17.0	18.4
Equity swap loss/(gain)	—	0.2	0.1	(1.2)
G&A expense	0.2	—	0.6	—
Total G&A expenses	$ 16.7	$ 16.3	$ 54.0	$ 56.7

(Per BOE)	Three months ended September 30, 2019	2018	Nine months ended September 30, 2019	2018
Cash:				
G&A expense	$ 1.19	$ 1.35	$ 1.32	$ 1.49
Share-based compensation expense	—	(0.02)	0.02	0.09
Non-Cash:				
Share-based compensation expense	0.48	0.48	0.63	0.74
Equity swap loss/(gain)	—	0.02	0.01	(0.05)
G&A expense	0.02	—	0.02	—
Total G&A expenses	$ 1.69	$ 1.83	$ 2.00	$ 2.27

For the three and nine months ended September 30, 2019, cash G&A expense was $11.7 million or $1.19/BOE and $35.5 million or $1.32/BOE, respectively, compared to $12.0 million or $1.35/BOE and $37.3 million or $1.49/BOE for the same periods in 2018. While total cash G&A expenses decreased, the more significant per BOE decrease was due to higher production when compared to the same periods in 2018.

During the third quarter of 2019, we reported a cash SBC expense of $0.1 million due to an increase in our share price on outstanding deferred share units. In comparison, during the same period of 2018, we recorded a cash SBC recovery of $0.2 million due to a decrease in our share price on outstanding deferred share units. In the third quarter of 2019, we recorded a non-cash SBC expense of $4.7 million or $0.48/BOE, consistent with $4.3 million or $0.48/BOE during the same period in 2018.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. Due to minimal share price movement over the third quarter of 2019, we recorded no mark-to-market gain or loss, compared to a loss of $0.2 million in the same period in 2018. At September 30, 2019, we had 264,000 units outstanding, hedged at a weighted average price of $17.82 per share.

Based on year-to-date spending, we are reducing our annual cash G&A guidance of $1.45/BOE to $1.40/BOE.

Interest Expense

For the three and nine months ended September 30, 2019, we recorded total interest expense of $7.9 million and $25.0 million, respectively, compared to $8.6 million and $27.0 million for the same periods in 2018. The decrease in interest expense for the nine months ended September 30, 2019 compared to the same period in 2018 was primarily due to the repayment of a portion of 2009 senior notes which carry a higher coupon rate compared to the remaining senior notes outstanding.

At September 30, 2019, we were undrawn on our bank credit facility and our debt balance consisted of fixed interest rate senior notes with a weighted average interest rate of 4.7%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Realized:				
Foreign exchange (gain)/loss on settlements	$ —	$ 0.3	$ —	$ 0.6
Translation of U.S. dollar cash held in Canada (gain)/loss	(1.5)	4.3	7.9	(6.8)
Unrealized (gain)/loss	8.6	(12.2)	(25.0)	17.9
Total foreign exchange (gain)/loss	$ 7.1	$ (7.6)	$ (17.1)	$ 11.7
USD/CDN average exchange rate	1.32	1.31	1.33	1.29
USD/CDN period end exchange rate	1.32	1.29	1.32	1.29

For the three and nine months ended September 30, 2019, we recorded a foreign exchange loss of $7.1 million and a gain of $17.1 million, respectively, compared to a gain of $7.6 million and a loss of $11.7 million for the same periods in 2018. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies, along with the translation of U.S. dollar denominated cash held in Canada, while unrealized gains and losses are recorded on the translation of U.S. dollar denominated debt and working capital at each period end. Comparing the period end exchange rate at September 30, 2019 to December 31, 2018, the Canadian dollar strengthened relative to the U.S. dollar, resulting in an unrealized gain of $25.0 million. See Note 13 to the Interim Financial Statements for further details.

Capital Investment

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Capital spending(1)	$ 151.5	$ 193.3	$ 519.5	$ 521.8
Office capital(1)	2.9	1.6	6.1	5.3
Line fill	—	—	5.1	—
Sub-total	154.4	194.9	530.7	527.1
Property and land acquisitions	$ 13.3	$ 1.7	$ 18.3	$ 16.4
Property divestments	0.2	0.8	(9.9)	(6.0)
Sub-total	13.5	2.5	8.4	10.4
Total	$ 167.9	$ 197.4	$ 539.1	$ 537.5

(1) Excludes changes in non-cash investing working capital. See Note 18(b) to the Interim Financial Statements for further details.

Capital spending for the three and nine months ended September 30, 2019 totaled $151.5 million and $519.5 million, respectively, compared to $193.3 million and $521.8 million for the same periods in 2018. The decrease in spending was due to lower completions activity in the third quarter of 2019 compared to the same period in 2018. During the third quarter of 2019, we invested $136.2 million in U.S. crude oil properties, $9.5 million in Marcellus natural gas assets and $6.2 million in Canadian waterflood properties. During the nine months ended September 30, 2019, we spent $5.1 million on line fill to meet the requirements of a multi-year transportation contract, which began in March 2019.

In the third quarter of 2019, we completed $13.3 million in property and land acquisitions, which consisted primarily of undeveloped land in North Dakota, compared to $1.7 million for the same period in 2018. Property divestments for the nine months ended September 30, 2019 were $9.9 million, which primarily related to the divestment of properties in Southeastern Saskatchewan with associated production of approximately 350 bbls/day.

We are revising our 2019 annual capital spending guidance to $625 million from $610 million to $630 million.

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

	Three months ended September 30,				Nine months ended September 30,			
($ millions, except per BOE amounts)		2019		2018		2019		2018
DD&A expense	$	94.4	$	81.5	$	258.6	$	218.7
Per BOE	$	9.57	$	9.15	$	9.58	$	8.74

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, 2019, DD&A increased to $94.4 million and $258.6 million, respectively, compared to $81.5 million and $218.7 million for the same periods in 2018. The increase in DD&A was a result of additional U.S. production with higher depletion rates combined with the impact of a weaker Canadian dollar on U.S. DD&A expense.

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. Impairments are non-cash and are not reversed in future periods under U.S. GAAP.

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 upcoming year, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. At September 30, 2019, SEC prices were above current commodity price levels. If commodity prices remain at current levels or decline further, SEC prices will be impacted. There have been no impairments recorded in the current or prior year. See Note 6 to the Interim Financial Statements for trailing twelve month prices.

Asset Retirement Obligation

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation, using a weighted average credit-adjusted risk-free rate of 5.53%, to be $130.2 million at September 30, 2019, compared to 5.59% and $126.1 million at December 31, 2018. For the three and nine months ended September 30, 2019, asset retirement obligation settlements were $2.9 million and $8.8 million, respectively, compared to $2.8 million and $8.1 million during the same periods in 2018. See Note 9 to the Interim Financial Statements for further details.

Leases

On January 1, 2019, we adopted ASU 842 – *Leases*, which requires the recognition of ROU assets and lease liabilities on the Condensed Consolidated Balance Sheet for qualifying leases with a term greater than 12 months. We incur lease payments related to office space, drilling rig commitments, vehicles and other equipment. Total lease liabilities included on our balance sheet are based on the present value of lease payments over the lease term. Total ROU assets included on our balance sheet represent our right to use an underlying asset for the lease term. At September 30, 2019, our total lease liability was $57.7 million. In addition, ROU assets of $53.5 million were recorded, which equate to our lease liabilities less lease incentives. See Note 3(a) and Note 10 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended September 30,				Nine months ended September 30,			
($ millions)		2019		2018		2019		2018
Current tax expense/(recovery)	$	—	$	0.1	$	(19.5)	$	0.2
Deferred tax expenses/(recovery)		18.6		15.0		49.5		30.7
Total tax expense/(recovery)	$	18.6	$	15.1	$	30.0	$	30.9

For the three and nine months ended September 30, 2019, we recorded a current tax recovery of nil and $19.5 million, respectively, compared to an expense of $0.1 million and $0.2 million for the same periods in 2018. The recovery in 2019 relates primarily to the favorable settlement of a tax dispute in Canada in the second quarter of 2019 and the reversal of the reserve recorded at December 31, 2017 for the sequestered portion of our U.S. AMT refund in the first quarter of 2019.

For the three and nine months ended September 30, 2019, we recorded a deferred tax expense of $18.6 million and $49.5 million, respectively, compared to $15.0 million and $30.7 million for the same periods in 2018. The increase in deferred tax expense in 2019 is primarily due to an expense recorded in the second quarter of 2019 for the remeasurement of our Canadian net deferred income tax asset to account for the change in the Alberta corporate income tax rate from 12% to 8% by 2022. See Note 14 to the Interim Financial Statements for further details.

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging, share repurchases 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, 2019, our senior debt to adjusted EBITDA ratio was 0.9x 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 liquidity.

Total debt net of cash at September 30, 2019 was $521.4 million, an increase of 56% compared to $333.5 million at December 31, 2018. The increase is primarily due to the use of cash on hand for the repurchase and cancellation of approximately 15.5 million common shares during the nine months ended September 30, 2019, for total consideration of $155.1 million. Total debt was comprised of $618.4 million of senior notes less $97.0 million in cash.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 92% and 104% for the three and nine months ended September 30, 2019, respectively, compared to 96% and 102% for the same periods in 2018.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $178.0 million at September 30, 2019 from $143.1 million at December 31, 2018. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, cash flow from operations and our bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

Subsequent to the quarter, we completed a two year extension of our senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2023. As part of the extension, we have amended the credit facility to US$600 million from CAD$800 million. There were no other significant amendments or additions to the agreement terms or covenants. Drawn fees on the facility range between 125 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 150 basis points over Banker's Acceptance rates based on our current reported senior net debt to adjusted EBITDA ratio. The bank credit facility ranks equally with our senior, unsecured covenant-based notes.

At September 30, 2019, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at September 30, 2019:

Covenant Description		September 30, 2019
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA [(1)]	3.5x	0.9x
Total debt to adjusted EBITDA [(1)]	4.0x	0.9x
Total debt to capitalization	50%	17%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA [(1)(2)]	3.0x - 3.5x	0.9x
Senior debt to consolidated present value of total proved reserves[(3)]	60%	18%
	Minimum Ratio	
Adjusted EBITDA to interest [(1)]	4.0x	21.2x

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, 2019 was $184.7 million and $737.4 million, respectively.
"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.
(2) Senior debt to adjusted EBITDA for the senior notes may increase to 3.5x for a period of 6 months, 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 September 30, 2019	2018	Nine months ended September 30, 2019	2018
Dividends to shareholders[1]	$ 6.8	$ 7.4	$ 21.0	$ 22.0
Per weighted average share (Basic)	$ 0.03	$ 0.03	$ 0.09	$ 0.09

(1) Excludes changes in non-cash financing working capital. See Note 18(b) to the Interim Financial Statements for further details.

During the three and nine months ended September 30, 2019, we reported total dividends of $6.8 million or $0.03 per share and $21.0 million or $0.09 per share, respectively, compared to $7.4 million or $0.03 per share and $22.0 million or $0.09 per share for the same periods in 2018. Dividends to shareholders have decreased compared to the same periods in 2018 as a result of our share repurchase program.

The dividend is part of our strategy to return capital to shareholders. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Nine months ended September 30, 2019	2018
Share capital ($ millions)	$ 3,126.1	$ 3,412.2
Common shares outstanding (thousands)	224,471	244,764
Weighted average shares outstanding – basic (thousands)	234,403	244,659
Weighted average shares outstanding – diluted (thousands)	237,399	250,048

For the nine months ended September 30, 2019, a total of 1,007,234 units vested pursuant to our treasury settled LTI plans (2018 – 2,539,498). In total, 564,000 shares were issued from treasury and $4.4 million was transferred from paid-in capital to share capital (2018 – 2,539,498; $23.4 million). We elected to cash settle the remaining units related to the required tax withholdings (2019 – $5.0 million, 2018 – nil).

For the nine months ended September 30, 2019, no shares were issued pursuant to our stock option plan, resulting in no additional share capital (2018 – 640,086; $8.7 million).

On March 21, 2019, Enerplus announced the renewal of its NCIB to purchase up to 16,673,015 common shares, representing 7% of the "public float" of Enerplus (within the meaning under the rules of the Toronto Stock Exchange (the "TSX")) through the facilities of the TSX, the New York Stock Exchange and/or alternative Canadian trading systems during the 12-month period ending March 25, 2020. On November 7, 2019, the Company's Board of Directors approved an increase to the maximum number of common shares that may be repurchased under the NCIB to up to 10% of public float (or an additional 7,145,578 common shares) until the expiry of the NCIB on March 25, 2020, subject to TSX approval.

During the nine months ended September 30, 2019, the Company repurchased 15,503,891 common shares under the previous and current NCIB at an average price of $10.00 per share, for total consideration of $155.1 million (2018 – 544,300; $8.5 million). Of the amount paid, $215.9 million was charged to share capital and $60.8 million was credited to accumulated deficit (2018 – $7.6 million; charge of $0.9 million). Subsequent to the quarter and up to November 6, 2019, the Company repurchased 2,727,510 common shares under the NCIB at an average price of $8.66 per share, for total consideration of $23.6 million.

On May 23, 2019, we filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces of Canada and a Registration Statement with the U.S. Securities Exchange Commission. The Shelf Prospectus allows us to offer and issue up to an aggregate amount of $2.0 billion of common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains in place.

At November 6, 2019, we had 221,743,701 common shares outstanding. In addition, an aggregate of 7,931,999 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU"), Restricted Share Unit, and stock option plans, assuming the maximum payout multiplier of 2.0 times for the PSUs.

For further details, see Note 15 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

($ millions, except per unit amounts)	Three months ended September 30, 2019 Canada	U.S.	Total	Three months ended September 30, 2018 Canada	U.S.	Total
Average Daily Production Volumes[(1)]						
Crude oil (bbls/day)	8,614	46,409	55,023	9,170	39,697	48,867
Natural gas liquids (bbls/day)	873	4,225	5,098	1,002	3,561	4,563
Natural gas (Mcf/day)	25,699	256,661	282,360	24,486	236,105	260,591
Total average daily production (BOE/day)	13,770	93,411	107,181	14,253	82,608	96,861
Pricing[(2)]						
Crude oil (per bbl)	$ 56.71	$ 69.82	$ 67.76	$ 69.12	$ 87.42	$ 83.98
Natural gas liquids (per bbl)	24.92	2.06	5.97	45.44	20.47	25.95
Natural gas (per Mcf)	0.79	2.26	2.13	2.78	3.27	3.22
Capital Expenditures						
Capital spending	$ 5.9	$ 145.6	$ 151.5	$ 15.3	$ 178.0	$ 193.3
Acquisitions	0.8	12.5	13.3	0.9	0.8	1.7
Divestments	0.2	—	0.2	1.1	(0.3)	0.8
Netback[(3)] Before Hedging						
Oil and natural gas sales	$ 49.5	$ 352.3	$ 401.8	$ 69.4	$ 397.0	$ 466.4
Royalties	(10.7)	(72.2)	(82.9)	(13.4)	(79.4)	(92.8)
Production taxes	(1.0)	(22.6)	(23.6)	(1.1)	(25.5)	(26.6)
Cash operating expenses	(15.4)	(54.2)	(69.6)	(19.1)	(41.5)	(60.6)
Transportation costs	(2.6)	(36.4)	(39.0)	(2.9)	(30.1)	(33.0)
Netback before hedging	$ 19.8	$ 166.9	$ 186.7	$ 32.9	$ 220.5	$ 253.4
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (20.2)	$ —	$ (20.2)	$ 54.1	$ —	$ 54.1
Total G&A[(4)]	9.0	7.7	16.7	9.9	6.4	16.3
Current income tax expense/(recovery)	—	—	—	(0.4)	0.5	0.1

($ millions, except per unit amounts)	Nine months ended September 30, 2019 Canada	U.S.	Total	Nine months ended September 30, 2018 Canada	U.S.	Total
Average Daily Production Volumes[(1)]						
Crude oil (bbls/day)	8,786	39,355	48,141	9,297	34,595	43,892
Natural gas liquids (bbls/day)	929	3,807	4,736	1,100	3,387	4,487
Natural gas (Mcf/day)	24,394	251,669	276,063	28,891	230,738	259,629
Total average daily production (BOE/day)	13,781	85,107	98,888	15,213	76,438	91,651
Pricing[(2)]						
Crude oil (per bbl)	$ 60.96	$ 71.58	$ 69.64	$ 62.78	$ 82.83	$ 78.58
Natural gas liquids (per bbl)	28.88	10.34	13.97	46.84	23.00	28.85
Natural gas (per Mcf)	2.38	3.06	3.00	2.67	3.19	3.14
Capital Expenditures						
Capital spending	$ 30.4	$ 489.1	$ 519.5	$ 39.8	$ 482.0	$ 521.8
Acquisitions	2.9	15.4	18.3	3.0	13.4	16.4
Divestments	(9.3)	(0.6)	(9.9)	0.3	(6.3)	(6.0)
Netback[(3)] Before Hedging						
Oil and natural gas sales	$ 171.4	$ 990.0	$ 1,161.4	$ 197.0	$ 1,004.8	$ 1,201.8
Royalties	(32.3)	(201.3)	(233.6)	(34.2)	(201.6)	(235.8)
Production taxes	(1.9)	(57.7)	(59.6)	(2.6)	(62.8)	(65.4)
Cash operating expenses	(54.0)	(157.3)	(211.3)	(57.3)	(118.0)	(175.3)
Transportation costs	(7.9)	(99.2)	(107.1)	(8.8)	(81.3)	(90.1)
Netback before hedging	$ 75.3	$ 474.5	$ 549.8	$ 94.1	$ 541.1	$ 635.2
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 37.3	$ —	$ 37.3	$ 165.5	$ —	$ 165.5
Total G&A[(4)]	20.2	33.8	54.0	31.6	25.1	56.7
Current income tax expense/(recovery)	(13.9)	(5.5)	(19.4)	(0.4)	0.6	0.2

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

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2019				
Third Quarter	$ 318.9	$ 65.1	$ 0.28	$ 0.28
Second Quarter	321.4	85.1	0.36	0.36
First Quarter	287.5	19.2	0.08	0.08
Total 2019	$ 927.8	$ 169.4	$ 0.72	$ 0.71
2018				
Fourth Quarter	$ 326.7	$ 249.4	$ 1.03	$ 1.02
Third Quarter	373.6	86.9	0.35	0.35
Second Quarter	327.4	12.4	0.05	0.05
First Quarter	265.0	29.6	0.12	0.12
Total 2018	$ 1,292.7	$ 378.3	$ 1.55	$ 1.53
2017				
Fourth Quarter	$ 271.1	$ 15.3	$ 0.06	$ 0.06
Third Quarter	196.1	16.1	0.07	0.07
Second Quarter	225.7	129.3	0.53	0.52
First Quarter	227.8	76.3	0.32	0.31
Total 2017	$ 920.7	$ 237.0	$ 0.98	$ 0.96

Oil and natural gas sales, net of royalties, and net income for the third quarter were in line with the second quarter of 2019. From the first quarter of 2019 to the second quarter of 2019, oil and natural gas sales, net of royalties, increased by $34.0 million due to increased production. Second quarter net income included a $27.4 million gain on commodity derivative instruments, compared to a loss of $84.9 million in the first quarter of 2019.

Oil and natural gas sales, net of royalties, increased in 2018 compared to 2017 due to an increase in realized commodity prices and a higher weighting of crude oil and natural gas liquids production. As a result, net income also improved in 2018, excluding the effects of a gain which was recorded on asset divestments in the second quarter of 2017.

2019 UPDATED GUIDANCE

We are narrowing our average annual production guidance range to 100,000 to 101,000 BOE/day from 99,000 to 102,000 BOE/day and narrowing our average annual crude oil and natural gas liquids guidance to 54,250 to 54,750 bbls/day from 54,000 to 55,500 bbls/day. In addition, we are providing fourth quarter average production guidance of 103,000 to 107,000 BOE/day, including average crude oil and natural gas liquids production of 58,000 to 60,000 bbls/day.

We are revising our 2019 capital spending guidance to $625 million from our previous range of $610 to $630 million and we are reducing our annual cash G&A guidance to $1.40/BOE from $1.45/BOE.

We are modifying our full year Bakken differential guidance to US$3.60/bbl below WTI from US$3.25/bbl.

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

Summary of 2019 Expectations	Target
Capital spending	$625 million (from $610 - $630 million)
Average annual production	100,000 - 101,000 BOE/day (from 99,000 - 102,000 BOE/day)
Average annual crude oil and natural gas liquids production	54,250 - 54,750 bbls/day (from 54,000 - 55,500 bbls/day)
Fourth quarter average production	103,000 - 107,000 BOE/day
Fourth quarter average crude oil and natural gas liquids production	58,000 - 60,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$7.90/BOE
Transportation costs	$4.00/BOE
Cash G&A expenses	$1.40/BOE (from $1.45/BOE)

2019 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.60)/bbl (from US$(3.25)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.35)/Mcf

(1) Excludes transportation costs.

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities:

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

Calculation of Netback	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Oil and natural gas sales	$ 401.8	$ 466.4	$ 1,161.4	$ 1,201.8
Less:				
Royalties	(82.9)	(92.8)	(233.6)	(235.8)
Production taxes	(23.6)	(26.6)	(59.6)	(65.4)
Cash operating expenses[(1)]	(69.6)	(60.6)	(211.3)	(175.3)
Transportation costs	(39.0)	(33.0)	(107.1)	(90.1)
Netback before hedging	$ 186.7	$ 253.4	$ 549.8	$ 635.2
Cash gains/(losses) on derivative instruments	5.2	(23.9)	14.6	(33.0)
Netback after hedging	$ 191.9	$ 229.5	$ 564.4	$ 602.2

(1) Cash operating expenses have been adjusted to exclude a non-cash loss of $0.1 million and nil for the three and nine months ended September 30, 2018, respectively.

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

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Cash flow from operating activities	$ 159.8	$ 216.1	$ 505.8	$ 517.2
Asset retirement obligation expenditures	2.9	2.8	8.8	8.1
Changes in non-cash operating working capital	12.6	(8.5)	15.5	13.9
Adjusted funds flow	$ 175.3	$ 210.4	$ 530.1	$ 539.2

"Free cash flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating and financial performance, leverage and liquidity. Free cash flow is calculated as adjusted funds flow minus capital spending.

Calculation of Free Cash Flow	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Adjusted funds flow	$ 175.3	$ 210.4	$ 530.1	$ 539.2
Capital spending	(151.5)	(193.3)	(519.5)	(521.8)
Free cash flow	$ 23.8	$ 17.1	$ 10.6	$ 17.4

"Adjusted net income" is used by Enerplus and is useful to investors and securities analysts in evaluating the financial performance of the Company by understanding the impact of certain non-cash items and other items that the Company considers appropriate to adjust given the irregular nature and relevance to comparable companies. Adjusted net income is calculated as net income adjusted for unrealized derivative instrument gain/loss, unrealized foreign exchange gain/loss, the tax effect of these items and the impact of statutory changes to the Company's corporate tax rate.

Calculation of Adjusted Net Income	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2019	2018	2019	2018
Net income/(loss)	$ 65.1	$ 86.9	$ 169.4	$ 129.0
Unrealized derivative instrument (gain)/loss	(14.9)	30.4	52.0	131.2
Unrealized foreign exchange (gain)/loss	8.6	(12.2)	(25.0)	17.9
Tax effect on above items	3.1	(7.9)	(14.0)	(35.4)
Income tax rate adjustment on deferred taxes	—	—	26.3	—
Adjusted net income	$ 61.9	$ 97.2	$ 208.7	$ 242.7

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

“**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 adjusted payout ratio as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2019**	**2018**	**2019**	**2018**
Dividends	$ 6.8	$ 7.4	$ 21.0	$ 22.0
Capital, office expenditures and line fill	154.4	194.9	530.7	527.1
Sub-total	$ 161.2	$ 202.3	$ 551.7	$ 549.1
Adjusted funds flow	$ 175.3	$ 210.4	$ 530.1	$ 539.2
Adjusted payout ratio (%)	92%	96%	104%	102%

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

Reconciliation of Net Income to Adjusted EBITDA[(1)]	
($ millions)	**September 30, 2019**
Net income/(loss)	$ 418.7
Add:	
Interest	34.8
Current and deferred tax expense/(recovery)	102.3
DD&A and asset impairment	344.2
Other non-cash charges[(2)]	(162.6)
Adjusted EBITDA	$ 737.4

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at September 30, 2019 include the nine months ended September 30, 2019 and the fourth quarter of 2018.
(2) Includes the change in fair value of commodity derivatives and equity swaps, non-cash SBC expense, non-cash G&A expense and unrealized foreign exchange gains/losses.

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”, “senior net debt to adjusted EBITDA”, “total debt to adjusted EBITDA”, “total debt to capitalization”, “senior 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 September 30, 2019, 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, 2019 and ended September 30, 2019 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

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

expected fourth quarter and 2019 average production volumes, timing thereof 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 2019 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; expected operating and transportation costs; our anticipated shares repurchases under current and future normal course issuer bids; capital spending levels in 2019 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; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; and the amount of future cash dividends that we may pay to our shareholders.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; the availability of third party services; and the extent of our liabilities. In addition, our updated 2019 guidance contained in this MD&A is based on the rest of the year prices of: a WTI price of US$54.00/bbl, a NYMEX price of US$2.40/Mcf, and a USD/CDN exchange rate of 1.32. 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 Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2018).

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.