Exhibit 99.1

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

The following discussion and analysis of financial results is dated November 5, 2020 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, 2020 and 2019 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2019 and 2018 and for the years ended December 31, 2019, 2018 and 2017; and
- our MD&A for the year ended December 31, 2019 (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. In addition, the following MD&A contains disclosure regarding certain risks and uncertainties associated with Enerplus' business. See "Risk Factors and Risk Management" in this MD&A and in the Annual MD&A and "Risk Factors" in Enerplus' annual information form for the year ended December 31, 2019 (the "Annual Information Form").

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 or 0.167:1, as applicable, utilizing a conversion on this 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 and realized product prices information is 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. All references to "liquids" in this MD&A include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and natural gas liquids on a combined basis.

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.

OVERVIEW

The coronavirus ("COVID-19") pandemic continues to have a major impact on the global economy. Although markets remain volatile and the timing of a full economic recovery remains uncertain, crude oil prices improved during the third quarter as supply moderated and demand levels began to recover from historically low levels. See "Risk Factors and Risk Management" related to COVID-19 in this MD&A.

In response to strengthening prices, our previously curtailed crude oil and natural gas liquids production was fully restored early in the third quarter and our crude oil and natural gas liquids production increased 9% to 52,539 bbls/day for the quarter, compared to 48,097 bbls/day in the second quarter of 2020. Total average production in the third quarter was 91,022 BOE/day, an increase of 4% from the second quarter of 2020.

As a result of strong production volumes during the third quarter, we are increasing our average annual production guidance for 2020 to 90,000 - 91,000 BOE/day, including 50,500 - 51,000 bbls/day of crude oil and natural gas liquids, from 88,000 - 90,000 BOE/day, including 49,000 - 50,000 bbls/day of crude oil and natural gas liquids. For the fourth quarter of 2020, we expect average production of 84,000 - 87,000 BOE/day, including average crude oil and natural gas liquids production of 47,000 - 49,000 bbls/day.

Capital expenditures during the third quarter of 2020 totaled $35.3 million, compared to $40.1 million during the second quarter, with approximately 80% of our annual capital budget spent year to date. As a result of strong operational performance to date, we are reducing our 2020 capital spending budget to $295 million from $300 million. Subsequent to the quarter, we completed four net operated wells in North Dakota and we continue to expect additional non-operated wells to come on-stream in North Dakota and the Marcellus prior to the end of the year.

Our realized Bakken crude oil price differential widened to average US$5.37/bbl below WTI during the third quarter compared to US$4.36/bbl below WTI during the second quarter. Bakken differentials in North Dakota were impacted by the uncertainty regarding the ongoing operation of the Dakota Access Pipeline ("DAPL"). We continue to expect our annual Bakken crude oil price differential to average US$5.00/bbl below WTI for 2020, assuming the continued operation of DAPL.

Our realized Marcellus natural gas price differential averaged US$0.72/Mcf below NYMEX in the third quarter, compared to US$0.49/Mcf below NYMEX during the second quarter, as storage levels during the shoulder season approached capacity. As a result of the differential widening during September and October, we are increasing our average annual Marcellus natural gas price differential to US$0.60/Mcf below NYMEX from US$0.45/Mcf below NYMEX.

Operating costs for the third quarter increased to $65.1 million or $7.78/BOE, compared to $54.4 million or $6.84/BOE in the second quarter, mainly due to previously curtailed production being restored in the third quarter of 2020 requiring additional well service activity and repairs and maintenance. As a result of cost savings to date, we are revising our annual operating expense guidance to $8.00/BOE from $8.25/BOE.

We are reducing our annual cash general and administrative guidance to $1.35/BOE from $1.40/BOE as a result of cash compensation reductions and other non-salary cost saving initiatives. We continue to maintain our annual average royalty and production tax rate of 26% of oil and natural gas sales before transportation and we are revising our annual transportation cost guidance to $4.00/BOE from $4.15/BOE.

We reported a net loss of $112.8 million in the third quarter of 2020 compared to $609.3 million in the second quarter of 2020. The net loss in the third quarter was primarily due to a non-cash impairment of $256.8 million on our property, plant and equipment ("PP&E") as a result of the low commodity price environment. We have recorded non-cash PP&E impairments of $683.6 million year to date, along with a non-cash goodwill impairment of $202.8 million during the second quarter as a result of low commodity prices and the continued market volatility.

Cash flow from operations increased to $137.0 million in the third quarter compared to $90.6 million in the second quarter of 2020 and adjusted funds flow increased to $83.1 million from $70.0 million over the same period. The increase was primarily due to higher production and an improvement in commodity prices during the quarter, offset by a $33.8 million decrease in realized gains on commodity derivative instruments compared to the second quarter of 2020.

We continue to expect our commodity hedging program to protect a portion of our cash flow from operating activities and adjusted funds flow. At September 30, 2020, our crude oil commodity derivative contracts were in a net asset position of $25.2 million. As of November 5, 2020, we have hedged 21,000 bbls/day of crude oil for the remainder of 2020 and 10,000 bbls/day for the first half of 2021. We have also hedged 40,000 Mcf/day of natural gas for the summer of 2021.

Despite the ongoing challenging market conditions, we have maintained a strong balance sheet. At September 30, 2020, our total debt net of cash was $428.8 million, including senior notes of $513.3 million and cash on hand of $84.5 million, and our net debt to adjusted funds flow ratio was 1.0x. At September 30, 2020, and as of the date of this MD&A, we are undrawn on our US$600 million bank credit facility and are in compliance with all debt covenants.

RESULTS OF OPERATIONS

Production

Daily production for the third quarter averaged 91,022 BOE/day, an increase of 4% compared to average production of 87,360 BOE/day in the second quarter of 2020. Crude oil and natural gas liquids production increased by 9% to 52,539 bbls/day over the same period as previously curtailed crude oil and natural gas liquids production was fully restored in the third quarter. Natural gas production decreased 2% to 230,895 Mcf/day compared to 235,579 Mcf/day during the second quarter due to minimal capital activity in the Marcellus throughout 2020.

For the three months ended September 30, 2020, total production decreased by 15% or 16,159 BOE/day compared to the same period in 2019. The decrease in crude oil production was a result of the suspension of our operated North Dakota drilling and completions program early in 2020 due to weak commodity prices, while natural gas production decreased over the same period due to limited capital activity in the Marcellus and our decision to shut-in, abandon and reclaim our Canadian natural gas property in Tommy Lakes during the first quarter of 2020. These impacts were partially offset by an increase in natural gas liquids production over the same period in part due to a 10% increase in natural gas liquids recoveries.

For the nine months ended September 30, 2020, total production decreased by 7% or 6,695 BOE/day compared to the same period in 2019. The decrease was mainly due to a 12% decline in natural gas production over the same period due to the reduced capital program in the Marcellus and the decision to shut-in certain non-core Canadian natural gas properties.

Our crude oil and natural gas liquids weighting increased to 58% in the third quarter of 2020 from 55% in the second quarter of 2020 and 56% in the third quarter of 2019.

Average daily production volumes for the three and nine months ended September 30, 2020 and 2019 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2020**	**2019**	**% Change**	**2020**	**2019**	**% Change**
Crude oil (bbls/day)	46,082	55,023	(16%)	46,098	48,141	(4%)
Natural gas liquids (bbls/day)	6,457	5,098	27%	5,581	4,736	18%
Natural gas (Mcf/day)	230,895	282,360	(18%)	243,083	276,063	(12%)
Total daily sales (BOE/day)	91,022	107,181	(15%)	92,193	98,888	(7%)

As a result of strong well performance in North Dakota, we are increasing our 2020 annual average production guidance range to 90,000 - 91,000 BOE/day from 88,000 - 90,000 BOE/day and increasing our crude oil and natural gas liquids production guidance range to 50,500 - 51,000 bbls/day from 49,000 - 50,000 bbls/day. In addition, we expect fourth quarter 2020 average production of 84,000 - 87,000 BOE/day, including average crude oil and natural gas liquids production of 47,000 - 49,000 bbls/day. This production guidance is based on a revised annual capital budget of $295 million, which includes the completion of four net operated wells in North Dakota during the fourth quarter. We continue to expect additional non-operated wells to come on-stream in North Dakota and the Marcellus prior to the end of the year.

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, 2020 and 2019 and other periods indicated:

	Nine months ended September 30,						
Pricing (average for the period)	**2020**	**2019**	**Q3 2020**	**Q2 2020**	**Q1 2020**	**Q4 2019**	**Q3 2019**
Benchmarks							
WTI crude oil (US$/bbl)	$ 38.32	$ 57.06	$ 40.93	$ 27.85	$ 46.17	$ 56.96	$ 56.45
Brent (ICE) crude oil (US$/bbl)	42.53	64.74	43.37	33.27	50.96	62.51	62.00
NYMEX natural gas – last day (US$/Mcf)	1.88	2.67	1.98	1.72	1.95	2.50	2.23
USD/CDN average exchange rate	1.35	1.33	1.33	1.39	1.34	1.32	1.32
USD/CDN period end exchange rate	1.33	1.32	1.33	1.36	1.41	1.30	1.32
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 43.21	$ 69.64	$ 46.43	$ 30.55	$ 51.30	$ 67.23	$ 67.76
Natural gas liquids ($/bbl)	7.88	13.97	10.60	(0.96)	12.72	18.28	5.97
Natural gas ($/Mcf)	1.82	3.00	1.72	1.63	2.08	2.50	2.13
Average differentials							
Bakken DAPL – WTI (US$/bbl)	$ (4.70)	$ (2.75)	$ (3.40)	$ (5.24)	$ (5.34)	$ (5.59)	$ (2.97)
Brent (ICE) – WTI (US$/bbl)	4.21	7.68	2.44	5.42	4.79	5.55	5.55
MSW Edmonton – WTI (US$/bbl)	(5.74)	(4.71)	(3.51)	(6.14)	(7.58)	(5.37)	(4.66)
WCS Hardisty – WTI (US$/bbl)	(13.69)	(11.73)	(9.08)	(11.47)	(20.53)	(15.83)	(12.24)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.55)	(0.38)	(0.80)	(0.45)	(0.39)	(0.70)	(0.48)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	(0.18)	0.34	(0.56)	(0.37)	0.41	(0.11)	(0.35)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI (US$/bbl)	$ (5.02)	$ (3.30)	$ (5.37)	$ (4.36)	$ (5.26)	$ (4.40)	$ (3.61)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.52)	(0.31)	(0.72)	(0.49)	(0.38)	(0.63)	(0.44)
Canada crude oil – WTI (US$/bbl)	(14.04)	(11.28)	(9.74)	(14.49)	(17.77)	(14.80)	(13.50)

(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 2020 averaged $46.43/bbl, an increase of 52% compared to the second quarter and consistent with the 47% increase in the benchmark WTI price over the same period. Crude oil prices and price differentials in both the U.S. and Canada strengthened as global crude oil demand began to recover from the significant drop in the previous quarter caused by the onslaught of the COVID-19 pandemic. An agreement made by the Organization of the Petroleum Exporting Countries Plus ("OPEC+") nations to curtail production from the market through 2020 and 2021 has led to modest global inventory draws and more stability in crude oil prices. Drilling activity in the U.S. remains at very low levels, which is expected to continue to have an impact on global supply levels over the near term.

Our realized Bakken crude oil price differential averaged US$5.37/bbl below WTI during the third quarter of 2020, which was US$1.01/bbl weaker than the second quarter of 2020. Bakken differentials in North Dakota were impacted by the uncertainty regarding the ongoing operation of DAPL. In early July, a U.S. district court ordered DAPL to cease operations after it determined that, due to deficiencies in the original environmental review, the U.S. Army Corps of Engineers was required to complete a more thorough Environmental Impact Statement. In early August, an appeals court granted the pipeline owners' request for a stay over the lower court order requiring the pipeline to cease operations. As a result, there is no outstanding court order in place requiring DAPL to shut down at this time and the legal process is ongoing.

Our Bakken crude oil sales portfolio 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 DAPL. In the third quarter, the premium associated with both Brent and U.S. Gulf Coast pricing moderated considerably, contributing to weaker realized sales differentials compared to the previous quarter.

Assuming the ongoing operation of DAPL, we continue to expect our annual Bakken crude oil price differential to average approximately US$5.00/bbl below WTI in 2020. Based on current market prices, we have fixed differential sales agreements in North Dakota for approximately 18,500 bbls/day at an estimated price of approximately US$5.50/bbl below WTI during the fourth quarter.

Our realized Canadian crude oil price differential narrowed by US$4.75/bbl compared to the second quarter of 2020, which was in line with changes to the underlying benchmark prices.

Our realized sales price for natural gas liquids averaged $10.60/bbl during the third quarter of 2020. Natural gas liquids prices recovered after experiencing particularly weak pricing during the second quarter due to the abrupt demand collapse caused by the COVID-19 pandemic.

NATURAL GAS

Our realized natural gas sales price averaged $1.72/Mcf during the third quarter, an increase of 6% compared to the second quarter of 2020. NYMEX benchmark prices increased by 15% over the same period due to much stronger demand for LNG exports in September and stagnant U.S. production throughout the summer.

Regional pricing in the Marcellus was particularly weak during the third quarter, especially in September, as a result of nearly full regional storage combined with low demand due to mild weather. As a result, our realized Marcellus sales price differential widened to average US$0.72/Mcf below NYMEX during the quarter compared to US$0.49/Mcf in the second quarter of 2020. Given the weakness in regional prices during September and October, we are adjusting our annual guidance for our Marcellus natural gas price differential to average US$0.60/Mcf below NYMEX in 2020 from US$0.45/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, the interest on our U.S. denominated debt, and the value of our outstanding U.S. senior notes.

The Canadian dollar weakened during the first nine months of 2020 in response to lower commodity prices as a result of the global excess supply of crude oil and the decreased demand impact of the COVID-19 pandemic. The USD/CDN exchange rate peaked at 1.45 USD/CDN in March and remained volatile throughout the second and third quarters of 2020, resulting in an average exchange rate of 1.35 USD/CDN during the first nine months of 2020 compared to 1.33 USD/CDN for the same period in 2019. The Canadian dollar weakened to 1.33 USD/CDN at September 30, 2020, compared to 1.30 USD/CDN at December 31, 2019.

Price Risk Management

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

We continue to expect our hedging contracts to protect a portion of our cash flow from operating activities and adjusted funds flow. As of November 5, 2020, we have hedged 21,000 bbls/day of crude oil for the remainder of 2020 and 10,000 bbls/day for the first half of 2021. We have also hedged 40,000 Mcf/day of natural gas for the period of April 1, 2021 to October 31, 2021. Our crude oil hedges consist of put spreads and three way collars in 2020, and three way collars in 2021. The put spreads and three way collars provide us with exposure to significant upward price movement; however, the sold put effectively limits the amount of downside protection we have 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 5, 2020:

	WTI Crude Oil (US$/bbl)		NYMEX Natural Gas (US$/Mcf)
	Oct 1, 2020 – Dec 31, 2020	**Jan 1, 2021 – Jun 30, 2021**	**Apr 1, 2021 – Oct 31, 2021**
Put Spreads[(1)]			
Volume (bbls/day)	16,000	—	—
Sold Puts[(2)]	$ 46.88	—	—
Purchased Puts	$ 57.50	—	—
Three Way Collars[(1)]			
Volume (bbls/day)	5,000	10,000	—
Sold Puts	$ 48.00	$ 32.00	—
Purchased Puts	$ 56.25	$ 40.80	—
Sold Calls	$ 65.00	$ 51.43	—
Swaps			
Volume (Mcf/day)	—	—	40,000
Sold Swaps	—	—	$ 2.96

(1) The total average deferred premium spent on our outstanding hedges is US$2.04/bbl from October 1, 2020 to December 31, 2020 and US$0.42/bbl from January 1, 2021 to June 30, 2021.
(2) The sold puts on the put spreads settle annually at the end of 2020.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2020**	**2019**	**2020**	**2019**
Cash gains/(losses):				
Crude oil	$ 19.7	$ (2.5)	$ 106.2	$ (10.4)
Natural gas	—	7.7	—	25.0
Total cash gains/(losses)	$ 19.7	$ 5.2	$ 106.2	$ 14.6
Non-cash gains/(losses):				
Crude oil	$ (18.8)	$ 20.5	$ 15.1	$ (42.8)
Natural gas	—	(5.5)	—	(9.1)
Total non-cash gains/(losses)	$ (18.8)	$ 15.0	$ 15.1	$ (51.9)
Total gains/(losses)	$ 0.9	$ 20.2	$ 121.3	$ (37.3)

	Three months ended September 30,		**Nine months ended September 30,**	
(Per BOE)	**2020**	**2019**	**2020**	**2019**
Total cash gains/(losses)	$ 2.36	$ 0.53	$ 4.21	$ 0.54
Total non-cash gains/(losses)	(2.25)	1.52	0.60	(1.93)
Total gains/(losses)	$ 0.11	$ 2.05	$ 4.81	$ (1.39)

We realized cash gains of $19.7 million and $106.2 million, respectively, on our crude oil contracts during the three and nine months ended September 30, 2020, compared to realized cash losses of $2.5 million and $10.4 million, respectively, for the same periods in 2019. Cash gains recorded during the nine months ended September 30, 2020 were primarily due to prices falling below the swap level as well as the net effect of benchmark prices below the put levels on both our put spreads and three way collars.

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, 2020, the fair value of crude oil contracts was in a net asset position of $25.2 million. For the three and nine months ended September 30, 2020, the change in the fair value of our crude oil contracts resulted in a loss of $18.8 million and a gain of $15.1 million, respectively. Our previous natural gas contracts were settled in the fourth quarter of 2019 and there were no natural gas derivative contracts outstanding during the nine months ended September 30, 2020.

Revenues

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2020	2019	2020	2019
Oil and natural gas sales	$ 239.9	$ 401.8	$ 680.8	$ 1,161.4
Royalties	(48.0)	(82.9)	(138.7)	(233.6)
Oil and natural gas sales, net of royalties	$ 191.9	$ 318.9	$ 542.1	$ 927.8

Oil and natural gas sales, net of royalties, for the three and nine months ended September 30, 2020 were $191.9 million and $542.1 million, respectively, a decrease of 40% and 42%, respectively, from the same periods in 2019. The decrease in revenue during the three and nine months ended September 30, 2020 was primarily due to weaker realized prices as a result of lower demand from the COVID-19 pandemic, along with a decrease in production volumes due to the suspension of our operated drilling program in North Dakota and limited capital activity in the Marcellus. Oil and natural gas sales, net of royalties, during the nine months ended September 30, 2020 were further impacted by price related production curtailments during the second quarter of 2020. Production volumes were fully restored early in the third quarter of 2020 as crude oil prices began to improve, resulting in a 57% increase in oil and natural gas sales, net of royalties, from the second quarter of 2020. See Note 11 to the Interim Financial Statements for further detail.

Royalties and Production Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2020	2019	2020	2019
Royalties	$ 48.0	$ 82.9	$ 138.7	$ 233.6
Per BOE	$ 5.73	$ 8.41	$ 5.49	$ 8.65
Production taxes	$ 13.6	$ 23.6	$ 36.7	$ 59.6
Per BOE	$ 1.63	$ 2.39	$ 1.45	$ 2.21
Royalties and production taxes	$ 61.6	$ 106.5	$ 175.4	$ 293.2
Per BOE	$ 7.36	$ 10.80	$ 6.94	$ 10.86
Royalties and production taxes (% of oil and natural gas sales)	26%	27%	26%	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. Royalties and production taxes for the three and nine months ended September 30, 2020 were $61.6 million and $175.4 million, respectively, a decrease of 42% and 40%, respectively, from the same periods in 2019. The decrease was primarily due to lower realized prices and a decrease in production volumes.

We continue to expect annual royalties and production taxes in 2020 to average 26% of oil and natural gas sales before transportation.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended September 30, 2020	2019	Nine months ended September 30, 2020	2019
Operating expenses	$ 65.1	$ 69.6	$ 198.5	$ 211.3
Per BOE	$ 7.78	$ 7.06	$ 7.86	$ 7.83

For the three and nine months ended September 30, 2020, operating expenses were $65.1 million or $7.78/BOE and $198.5 million or $7.86/BOE, respectively. Operating expenses decreased during the nine months ended September 30, 2020 compared to the same period of 2019 primarily due to lower production volumes during the second quarter of 2020. This decrease was partially offset by additional well service activity and repairs and maintenance required during the third quarter of 2020 as previously curtailed production was restored.

Operating expenses increased on a per BOE basis in 2020 compared to the prior year primarily due to a decrease in Marcellus natural gas production volumes which have lower associated operating costs.

As a result of cost savings to date, we are reducing our 2020 annual operating cost guidance to $8.00/BOE from $8.25/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended September 30, 2020	2019	Nine months ended September 30, 2020	2019
Transportation costs	$ 32.2	$ 39.0	$ 101.5	$ 107.1
Per BOE	$ 3.85	$ 3.96	$ 4.02	$ 3.97

For the three and nine months ended September 30, 2020, transportation costs were $32.2 million or $3.85/BOE and $101.5 million or $4.02/BOE, respectively, a decrease compared to $39.0 million or $3.96/BOE and $107.1 million or $3.97/BOE, respectively, for the same periods in 2019. The reduction in transportation costs was primarily due to lower U.S. crude oil production with higher associated transportation costs compared to the same periods in 2019 as a result of price related production curtailments that impacted our crude oil and natural gas liquids volumes during the second quarter of 2020.

We are reducing our 2020 annual transportation cost guidance to $4.00/BOE from $4.15/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.

Netbacks by Property Type	Three months ended September 30, 2020 Crude Oil	Natural Gas	Total
Average Daily Production	57,945 BOE/day	198,464 Mcfe/day	91,022 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 39.17	$ 1.71	$ 28.65
Royalties and production taxes	(10.22)	(0.39)	(7.36)
Operating expenses	(11.05)	(0.34)	(7.78)
Transportation costs	(2.72)	(0.97)	(3.85)
Netback before hedging	$ 15.18	$ 0.01	$ 9.66
Cash hedging gains/(losses)	3.70	—	2.36
Netback after hedging	$ 18.88	$ 0.01	$ 12.02
Netback before hedging ($ millions)	$ 80.8	$ 0.2	$ 81.0
Netback after hedging ($ millions)	$ 100.5	$ 0.2	$ 100.7

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

Netbacks by Property Type	Three months ended September 30, 2019		
	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)
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

Netbacks by Property Type	Nine months ended September 30, 2020		
	Crude Oil	**Natural Gas**	**Total**
Average Daily Production	56,433 BOE/day	214,558 Mcfe/day	92,193 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 36.87	$ 1.88	$ 26.95
Royalties and production taxes	(9.89)	(0.38)	(6.94)
Operating expenses	(11.67)	(0.31)	(7.86)
Transportation costs	(2.94)	(0.95)	(4.02)
Netback before hedging	$ 12.37	$ 0.24	$ 8.13
Cash hedging gains/(losses)	6.87	—	4.21
Netback after hedging	$ 19.24	$ 0.24	$ 12.34
Netback before hedging ($ millions)	$ 191.3	$ 14.1	$ 205.4
Netback after hedging ($ millions)	$ 297.5	$ 14.1	$ 311.6

Netbacks by Property Type	Nine months ended September 30, 2019		
	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)
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

Our netbacks in 2020 have been impacted by the low commodity price environment. Total netbacks before hedging decreased 57% and 63% during the three and nine months ended September 30, 2020, respectively, compared to the same periods in 2019. Our price risk management program continues to provide funds flow protection, with realized cash gains on our crude oil hedging derivatives partially offsetting the impact of lower realized prices and improving total netbacks after hedging.

For the three and nine months ended September 30, 2020, our crude oil properties accounted for 100% and 93% of our total netback before hedging, respectively, compared to 91% and 83% during the same periods in 2019.

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(b) to the Interim Financial Statements for further details.

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2020	2019	2020	2019
Cash:				
G&A expense	$ 11.6	$ 11.7	$ 33.3	$ 35.5
Share-based compensation expense	(0.7)	0.1	(2.3)	0.8
Non-Cash:				
Share-based compensation expense	(2.8)	4.7	8.5	17.0
Equity swap loss/(gain)	0.4	—	1.8	0.1
G&A expense	(0.1)	0.2	(0.2)	0.6
Total G&A expenses	$ 8.4	$ 16.7	$ 41.1	$ 54.0

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2020	2019	2020	2019
Cash:				
G&A expense	$ 1.40	$ 1.19	$ 1.33	$ 1.32
Share-based compensation expense	(0.09)	—	(0.09)	0.02
Non-Cash:				
Share-based compensation expense	(0.33)	0.48	0.33	0.63
Equity swap loss/(gain)	0.05	—	0.07	0.01
G&A expense	(0.01)	0.02	(0.01)	0.02
Total G&A expenses	$ 1.02	$ 1.69	$ 1.63	$ 2.00

Cash G&A expenses for the three and nine months ended September 30, 2020 were $11.6 million or $1.40/BOE and $33.3 million or $1.33/BOE, respectively, compared to $11.7 million or $1.19/BOE and $35.5 million or $1.32/BOE for the same periods in 2019. Cash G&A expenses decreased during the nine months ended September 30, 2020 compared to the same period in 2019 due to a reduction in salaries and other non-salary cost saving initiatives.

During the third quarter of 2020, we reported a cash SBC recovery of $0.7 million due to the impact of a lower share price on our outstanding Director Deferred Share Units ("DSUs"). In comparison, during the same period of 2019, we recorded a cash SBC expense of $0.1 million as a result of an increase in our share price. We recorded a non-cash SBC recovery of $2.8 million during the third quarter of 2020 due to the impact of a reduction in the performance multiplier on our outstanding Performance Share Units ("PSUs"), compared to an expense of $4.7 million or $0.48/BOE during the same period in 2019.

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the third quarter of 2020, we recorded a mark-to-market loss of $0.4 million on these contracts, with no change in the same period of 2019.

As a result of cost savings to date, we are reducing our 2020 annual cash G&A guidance to $1.35/BOE from $1.40/BOE.

Interest Expense

For the three and nine months ended September 30, 2020, we recorded total interest expense of $6.3 million and $22.3 million, respectively, compared to $7.9 million and $25.0 million for the same periods in 2019. The decrease in interest expense in the third quarter of 2020 was primarily due to the repayment of a portion of our 2009 and 2012 senior notes during the second quarter of 2020.

At September 30, 2020, our debt balance consisted primarily of fixed interest rate senior notes with a weighted average interest rate of 4.6%. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended September 30, 2020	Three months ended September 30, 2019	Nine months ended September 30, 2020	Nine months ended September 30, 2019
Realized foreign exchange (gain)/loss:				
Foreign exchange (gain)/loss on settlements	$ 0.4	$ —	$ 0.4	$ —
Translation of U.S. dollar cash held in Canada (gain)/loss	—	(1.5)	(2.7)	7.9
Unrealized foreign exchange (gain)/loss	0.5	8.6	(0.9)	(25.0)
Total foreign exchange (gain)/loss	$ 0.9	$ 7.1	$ (3.2)	$ (17.1)
USD/CDN average exchange rate	1.33	1.32	1.35	1.33
USD/CDN period end exchange rate	1.33	1.32	1.33	1.32

For the three and nine months ended September 30, 2020, we recorded a foreign exchange loss of $0.9 million and a foreign exchange gain of $3.2 million, respectively, compared to a loss of $7.1 million and a gain of $17.1 million for the same periods in 2019. Realized foreign exchange gains and losses relate primarily to day-to-day transactions recorded in foreign currencies and the translation of our U.S. dollar denominated cash held in Canada, while unrealized foreign exchange gains and losses are recorded on the translation of our U.S. dollar denominated bank debt and working capital held in Canada at each period end.

Effective January 1, 2020, we have designated our outstanding senior notes as a net investment hedge related to our U.S. operations. As a result of the adoption of net investment hedge accounting, any unrealized foreign exchange gains and losses on the translation of this U.S. dollar denominated debt are included in Other Comprehensive Income/(Loss). At September 30, 2020, US$385.4 million of senior notes outstanding were designated as a net investment hedge. For the three and nine months ended September 30, 2020, Other Comprehensive Income/(Loss) included an unrealized gain of $9.9 million and a loss of $20.7 million, respectively, on our outstanding U.S. dollar denominated senior notes. See Note 3(a) to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended September 30, 2020	Three months ended September 30, 2019	Nine months ended September 30, 2020	Nine months ended September 30, 2019
Capital spending(1)	$ 35.3	$ 151.5	$ 239.1	$ 519.5
Office capital(1)	0.9	2.9	3.7	6.1
Line fill	—	—	—	5.1
Sub-total	36.2	154.4	242.8	530.7
Property and land acquisitions	$ 2.4	$ 13.3	$ 8.1	$ 18.3
Property divestments	(0.6)	0.2	(6.1)	(9.9)
Sub-total	1.8	13.5	2.0	8.4
Total	$ 38.0	$ 167.9	$ 244.8	$ 539.1

(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, 2020 decreased to $35.3 million and $239.1 million, respectively, compared to $151.5 million and $519.5 million for the same periods in 2019. The decrease was mainly due to minimal drilling and completions activity in North Dakota during the second and third quarters of 2020 in response to low crude oil prices as a result of the COVID-19 pandemic. Capital spending during the third quarter included $17.3 million on our U.S. crude oil properties, $10.8 million on our Marcellus natural gas assets and $5.6 million on our Canadian waterflood properties.

During the third quarter of 2020, we completed $2.4 million in property and land acquisitions, which included minor acquisitions of leases and undeveloped land, compared to $13.3 million for the same period in 2019.

As a result of strong operational performance to date, we are revising our capital spending guidance to $295 million from $300 million. Subsequent to the quarter, we completed four net operated wells in North Dakota and we continue to expect additional non-operated wells to come on-stream in North Dakota and the Marcellus prior to the end of the year.

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

($ millions, except per BOE amounts)	Three months ended September 30, 2020	Three months ended September 30, 2019	Nine months ended September 30, 2020	Nine months ended September 30, 2019
DD&A expense	$ 62.1	$ 94.4	$ 237.2	$ 258.6
Per BOE	$ 7.42	$ 9.57	$ 9.39	$ 9.58

DD&A of PP&E is recognized using the unit-of-production method based on proved reserves. For the three and nine months ended September 30, 2020, DD&A expense decreased compared to the same periods of 2019 as a result of lower overall production volumes and the impact of PP&E impairments and decreased capital activity in 2020.

Impairment

PP&E

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. See Note 6(a) to the Interim Financial Statements for trailing twelve month prices.

Trailing twelve month average crude oil and natural gas prices declined throughout the first nine months of 2020. For the three months ended September 30, 2020, we recorded a non-cash PP&E impairment of $256.8 million (Canadian cost centre: $23.3 million, U.S. cost centre: $233.5 million). For the nine months ended September 30, 2020, we recorded a non-cash PP&E impairment of $683.6 million (Canadian cost centre: $100.8 million, U.S. cost centre $582.8 million). There were no impairments recorded for the same periods in 2019.

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 2020, 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. If commodity prices remain at current levels, the twelve month trailing prices will decline further, impacting the ceiling value and resulting in an increased risk of future PP&E impairments. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties, Deferred Tax Assets and Goodwill" in the Annual MD&A and "Risk Factors and Risk Management" in this MD&A.

Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Goodwill is assessed for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus first performs a qualitative assessment to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to the reporting unit's fair value, with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). The loss recognized should not exceed the total amount of goodwill allocated to that reporting unit.

During the second quarter of 2020, we recorded a non-cash goodwill impairment charge of $202.8 million related to our U.S. reporting unit. The impairment was a result of the deterioration in macroeconomic conditions and low commodity prices due to the COVID-19 pandemic, which resulted in a reduction in the fair value of the U.S. reporting unit and a full write down of our U.S. goodwill asset. There was no goodwill impairment during the same period of the prior year. In the fourth quarter of 2019, we recorded a goodwill impairment of $451.1 million representing the full value of the goodwill attributable to our Canadian reporting unit. At September 30, 2020, there was no goodwill remaining on our Condensed Consolidated Balance Sheet.

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 the Condensed Consolidated 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 5.35%, to be $147.1 million at September 30, 2020, compared to $138.0 million at December 31, 2019, using a weighted average credit-adjusted risk-free rate of 5.50%. For the three and nine months ended September 30, 2020, asset retirement obligation settlements were $1.9 million and $13.0 million, respectively, compared to $2.9 million and $8.8 million during the same periods in 2019. See Note 9 to the Interim Financial Statements for further details.

Leases

Enerplus recognizes right-of-use ("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 are based on the present value of lease payments over the lease term. Total ROU assets represent our right to use an underlying asset for the lease term. At September 30, 2020, our total lease liability was $40.4 million (December 31, 2019 - $53.1 million). In addition, ROU assets of $36.1 million were recorded, which equate to our lease liabilities less lease incentives (December 31, 2019 - $48.7 million). See Note 10 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2020	2019	2020	2019
Current tax expense/(recovery)	$ (0.1)	$ —	$ (14.5)	$ (19.5)
Deferred tax expense/(recovery)	(140.0)	18.6	(129.6)	49.5
Total tax expense/(recovery)	$ (140.1)	$ 18.6	$ (144.1)	$ 30.0

For the nine months ended September 30, 2020, we recorded a current tax recovery of $14.5 million compared to a recovery of $19.5 million for the same period in 2019. The recovery in 2020 related to the recognition of our final U.S. Alternative Minimum Tax ("AMT") refund. In 2019, the recovery related primarily to the favorable settlement of a tax dispute in Canada.

For the three and nine months ended September 30, 2020, we recorded a deferred income tax recovery of $140.0 million and $129.6 million, respectively, compared to an expense of $18.6 million and $49.5 million, respectively, for the same periods in 2019. The deferred tax recovery in the third quarter of 2020 was primarily due to lower net income and a valuation allowance recovery of $73.8 million previously recorded against our Canadian deferred income tax assets.

Each period, we assess the recoverability of our deferred tax assets to determine whether it is more likely than not all or a portion of our deferred tax assets will not be realized. In making that assessment, we consider the available positive and negative evidence including future taxable income and reversing existing temporary differences. We evaluated the overall net deferred income tax asset and concluded that it is more likely than not that a portion of our Canadian deferred income tax assets will be realized as there is sufficient future taxable income to realize the benefit. As a result, for the three months ended September 30, 2020, we recovered a portion of the valuation allowance previously recorded against the Canadian deferred income tax assets. No valuation allowance was recorded against our U.S. deferred income tax assets. This assessment was primarily the result of projecting future taxable income using total proved and probable reserves at forecast average prices and costs. There is risk of further valuation allowance in future periods if commodity prices weaken or other evidence indicates more of our deferred income tax assets will not be realized. After recording the valuation allowance recovery, our overall net deferred income tax asset was $503.5 million as at September 30, 2020 (December 31, 2019 - $372.5 million).

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, 2020, our senior debt to adjusted EBITDA ratio was 1.2x and our net debt to adjusted funds flow ratio was 1.0x. 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. Refer to the definitions and footnotes below.

At September 30, 2020, we had $84.5 million of cash on hand. Total debt net of cash at September 30, 2020 was $428.8 million, a decrease of 6% compared to $455.0 million at December 31, 2019. During the second quarter, we made scheduled repayments of US$81.6 million on our 2009 and 2012 senior notes using cash on hand.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, for the three and nine months ended September 30, 2020 was 52% and 99%, respectively, compared to 92% and 104%, respectively, for the same periods in 2019.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $258.1 million at September 30, 2020, from $210.4 million at December 31, 2019. We expect to finance our working capital deficit and our ongoing working capital requirements through cash on hand, cash flow from operations and our bank credit facility. We continue to expect to be able to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

During the first quarter of 2020, we repurchased and cancelled 340,434 common shares for total consideration of $2.5 million under our Normal Course Issuer Bid ("NCIB") prior to its expiry on March 25, 2020. Given the environment, we chose not to renew our NCIB in order to preserve capital and maintain our balance sheet strength and liquidity. We plan to renew our NCIB in due course and recommence our share repurchase program when market conditions improve.

At September 30, 2020, we were undrawn on our US$600 million bank credit facility and in compliance with all covenants under our bank credit facility and outstanding senior notes. If we exceed or anticipate exceeding our covenants, we may be required to repay, refinance or renegotiate the terms of the debt. See "Risk Factors – Debt covenants of the Corporation may be exceeded with no ability to negotiate covenant relief" in the Annual Information Form and "Risk Factors and Risk Management" in this MD&A. 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, 2020:

Covenant Description		September 30, 2020
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.2x
Total debt to adjusted EBITDA (1)	4.0x	1.2x
Total debt to capitalization	55%	22%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.2x
Senior debt to consolidated present value of total proved reserves(3)	60%	17%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	14.4x

Definitions
"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended September 30, 2020 was $89.2 million and $449.7 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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per share amounts)	2020	2019	2020	2019
Dividends to shareholders(1)	$ 6.7	$ 6.8	$ 20.0	$ 21.0
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, 2020, we declared total dividends of $6.7 million or $0.03 per share and $20.0 million or $0.09 per share, respectively, compared to $6.8 million or $0.03 per share and $21.0 million or $0.09 per share, respectively, for the same periods in 2019. The total amount of dividends paid to shareholders has decreased compared to the same periods in 2019 as a result of our share repurchase program.

The dividend is part of our current 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,	
	2020	2019
Share capital ($ millions)	$ 3,097.0	$ 3,126.1
Common shares outstanding (thousands)	222,548	224,471
Weighted average shares outstanding – basic (thousands)	222,487	234,403
Weighted average shares outstanding – diluted (thousands)	222,487	237,399

For the nine months ended September 30, 2020, a total of 2,044,718 units vested pursuant to our treasury settled LTI plans, including the impact of performance multipliers (2019 – 1,007,234). In total, 1,160,000 shares were issued from treasury and $13.8 million was transferred from paid-in capital to share capital (2019 – 564,000; $4.4 million). We elected to cash settle the remaining units related to the required tax withholdings (2020 – $7.2 million, 2019 – $5.0 million).

During the nine months ended September 30, 2020, we repurchased 340,434 common shares under the previous NCIB at an average price of $7.44 per share, for total consideration of $2.5 million (2019 – 8,358,821; $90.4 million). Of the amount paid, $4.7 million was charged to share capital and $2.2 million was credited to accumulated deficit (2019 – $116.4 million; $26.0 million). There were no share repurchases during the three months ended September 30, 2020, as we chose not to renew our NCIB after its expiry on March 25, 2020 in order to preserve capital and maintain our balance sheet strength.

At November 5, 2020, we had 222,547,600 common shares outstanding. In addition, an aggregate of 6,995,939 common shares may be issued to settle outstanding grants under the Performance Share Unit ("PSU") and Restricted Share Unit plans assuming the maximum performance 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

	Three months ended September 30, 2020			Three months ended September 30, 2019		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	7,398	38,684	46,082	8,614	46,409	55,023
Natural gas liquids (bbls/day)	608	5,849	6,457	873	4,225	5,098
Natural gas (Mcf/day)	12,196	218,699	230,895	25,699	256,661	282,360
Total average daily production (BOE/day)	10,039	80,983	91,022	13,770	93,411	107,181
Pricing[2]						
Crude oil (per bbl)	$ 41.21	$ 47.43	$ 46.43	$ 56.71	$ 69.82	$ 67.76
Natural gas liquids (per bbl)	19.38	9.69	10.60	24.92	2.06	5.97
Natural gas (per Mcf)	2.89	1.65	1.72	0.79	2.26	2.13
Capital Expenditures						
Capital spending	$ 5.8	$ 29.5	$ 35.3	$ 5.9	$ 145.6	$ 151.5
Acquisitions	0.7	1.7	2.4	0.8	12.5	13.3
Divestments	—	(0.6)	(0.6)	0.2	—	0.2
Netback[3] Before Hedging						
Oil and natural gas sales	$ 32.7	$ 207.2	$ 239.9	$ 49.5	$ 352.3	$ 401.8
Royalties	(5.0)	(43.0)	(48.0)	(10.7)	(72.2)	(82.9)
Production taxes	(0.4)	(13.2)	(13.6)	(1.0)	(22.6)	(23.6)
Operating expenses	(13.0)	(52.1)	(65.1)	(15.4)	(54.2)	(69.6)
Transportation costs	(2.5)	(29.7)	(32.2)	(2.6)	(36.4)	(39.0)
Netback before hedging	$ 11.8	$ 69.2	$ 81.0	$ 19.8	$ 166.9	$ 186.7
Other Expenses						
Asset impairment	$ 23.3	$ 233.5	$ 256.8	$ —	$ —	$ —
Commodity derivative instruments loss/(gain)	(0.9)	—	(0.9)	(20.2)	—	(20.2)
Total G&A (including SBC)	(0.3)	8.7	8.4	9.0	7.7	16.7
Current income tax expense/(recovery)	—	(0.1)	(0.1)	—	—	—

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

($ millions, except per unit amounts)	Nine months ended September 30, 2020 Canada	U.S.	Total	Nine months ended September 30, 2019 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	7,101	38,997	46,098	8,786	39,355	48,141
Natural gas liquids (bbls/day)	644	4,937	5,581	929	3,807	4,736
Natural gas (Mcf/day)	13,137	229,946	243,083	24,394	251,669	276,063
Total average daily production (BOE/day)	9,935	82,258	92,193	13,781	85,107	98,888
Pricing[2]						
Crude oil (per bbl)	$ 34.18	$ 44.86	$ 43.21	$ 60.96	$ 71.58	$ 69.64
Natural gas liquids (per bbl)	19.70	6.34	7.88	28.88	10.34	13.97
Natural gas (per Mcf)	2.41	1.79	1.82	2.38	3.06	3.00
Capital Expenditures						
Capital spending	$ 20.6	$ 218.5	$ 239.1	$ 30.4	$ 489.1	$ 519.5
Acquisitions	2.2	5.9	8.1	2.9	15.4	18.3
Divestments	0.1	(6.2)	(6.1)	(9.3)	(0.6)	(9.9)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 80.2	$ 600.6	$ 680.8	$ 171.4	$ 990.0	$ 1,161.4
Royalties	(12.4)	(126.3)	(138.7)	(32.3)	(201.3)	(233.6)
Production taxes	(0.6)	(36.1)	(36.7)	(1.9)	(57.7)	(59.6)
Operating expenses	(41.9)	(156.6)	(198.5)	(54.0)	(157.3)	(211.3)
Transportation costs	(6.2)	(95.3)	(101.5)	(7.9)	(99.2)	(107.1)
Netback before hedging	$ 19.1	$ 186.3	$ 205.4	$ 75.3	$ 474.5	$ 549.8
Other Expenses						
Asset impairment	$ 100.8	$ 582.8	$ 683.6	$ —	$ —	$ —
Goodwill impairment	—	202.8	202.8	—	—	—
Commodity derivative instruments loss/(gain)	(121.3)	—	(121.3)	37.3	—	37.3
Total G&A (including SBC)	(1.0)	42.1	41.1	20.3	33.8	54.1
Current income tax expense/(recovery)	—	(14.5)	(14.5)	(13.9)	(5.5)	(19.4)

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

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
2020				
Third Quarter	$ 191.9	$ (112.8)	$ (0.51)	$ (0.51)
Second Quarter	122.1	(609.3)	(2.74)	(2.74)
First Quarter	228.1	2.9	0.01	0.01
Total 2020	$ 542.1	$ (719.2)	$ (3.23)	$ (3.23)
2019				
Fourth Quarter	$ 327.0	$ (429.1)	$ (1.93)	$ (1.93)
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	$ 1,254.8	$ (259.7)	$ (1.12)	$ (1.12)
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

Oil and natural gas sales, net of royalties, increased to $191.9 million during the third quarter of 2020 compared to $122.1 million in the second quarter of 2020. We began restoring curtailed production volumes in June as crude oil prices improved, with production fully restored in the third quarter. We reported a net loss of $112.8 million during the third quarter of 2020 compared to $609.3 million in the second quarter of 2020. The net loss in the third quarter was impacted by non-cash PP&E impairments of $256.8 million, while second quarter earnings were reduced by a $426.8 million non-cash impairment of PP&E, a $202.8 million non-cash impairment of our U.S. goodwill asset and a $142.2 million decrease in gains on commodity derivative instruments.

Oil and natural gas sales, net of royalties, in 2019 were essentially flat when compared to 2018 due to lower realized commodity prices being offset by increased production. We reported a net loss in 2019 due to a non-cash impairment of $451.1 million on our Canadian goodwill asset recorded in the fourth quarter of 2019 and a loss on commodity derivative instruments of $66.1 million compared to a gain of $88.2 million recorded in 2018.

RECENT ACCOUNTING STANDARDS

We have not early adopted any accounting standard, interpretation or amendment that has been issued but is not yet effective. Our significant accounting policies remain unchanged from December 31, 2019, other than as described in Note 3 to the Interim Financial Statements, "Accounting Policy Changes".

RISK FACTORS AND RISK MANAGEMENT

Risks Relating to the Impact of the COVID-19 Pandemic and Continued Weakness and Volatility in Commodity Prices

The global outbreak of the COVID-19 pandemic and the ongoing uncertainty as to the extent and duration of this pandemic, as well as governmental authorities response thereto, has resulted in, and continues to result in, among other things: increased volatility in financial markets, including credit markets and foreign currency and interest exchange rates; disruptions to global supply chains; labour shortages; reductions in trade volumes; temporary operational restrictions, quarantine orders, business closures and travel bans; an overall slowdown in the global economy; political and economic instability; and civil unrest. In particular, the COVID-19 pandemic has resulted in, and continues to result in, a reduction in the demand for crude oil and natural gas.

In addition, recent market events and conditions, including excess global crude oil and natural gas supply and decreased global demand due to the COVID-19 pandemic, have caused significant weakness and volatility in commodity prices. While the commodity prices began to stabilize as global economies began to re-open in June, the recent resurgence of COVID-19 cases in certain geographic areas, and the possibility that a resurgence may occur in other areas, has resulted in the re-imposition of certain restrictions noted above by local authorities. This further increases the risk and uncertainty as to the extent and duration of the COVID-19 pandemic and the resultant impact on commodity demand and prices. The overall result of these recent events and conditions could lead to a prolonged period of depressed prices for crude oil and natural gas which may result in further curtailments, voluntary or otherwise. We are continuing to evaluate the impact of the COVID-19 pandemic and the continued commodity environment instability on our business, financial condition and results of operations; however, the full extent of such impact continues to be unknown at this time and will depend on future developments (which are highly uncertain and cannot be predicted with any degree of confidence) and may be adverse and could result, among other things, in PP&E or deferred tax asset impairment, or exceeding our debt covenants, among others. See disclosure under "Impairment – PP&E", “Income Taxes” and "Liquidity and Capital Resources" in this MD&A.

We are also subject to risks relating to the health and safety of our personnel, including the potential for a slowdown or temporary suspension of our operations in locations impacted by an outbreak or further regulatory changes. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This would negatively impact our production volumes, which could adversely impact our business, financial condition and results of operations.

Depending on the extent and duration of the COVID-19 pandemic, it may also have the effect of heightening many of the other risks described in the Annual Information Form and the Annual MD&A.

2020 UPDATED GUIDANCE

We are increasing our 2020 annual average production guidance range to 90,000 - 91,000 BOE/day and increasing our crude oil and natural gas liquids production guidance range to 50,500 - 51,000 bbls/day. This annual production guidance is based on a revised capital budget of $295 million. In addition, we are providing 2020 fourth quarter average production guidance of 84,000 - 87,000 BOE/day, including crude oil and natural gas liquids production of 47,000 - 49,000 bbls/day.

Based on continued improvements in cost structures, we are reducing our guidance for 2020 annual operating expenses, transportation costs and cash G&A expenses by a combined $0.45/BOE.

We are revising our annual Marcellus natural gas price differential to US$0.60/Mcf below NYMEX from US$0.45/Mcf below NYMEX.

Our average royalty and production tax rate guidance and expected annual Bakken crude oil price differential remains unchanged. This guidance does not include any additional acquisitions or divestments.

Summary of 2020 Annual Expectations	Target Annual Results
Capital spending	$295 million (from $300 million)
Average annual production	90,000 - 91,000 BOE/day (from 88,000 - 90,000 BOE/day)
Average annual crude oil and natural gas liquids production	50,500 - 51,000 bbls/day (from 49,000 - 50,000 bbls/day)
Fourth quarter average production	84,000 - 87,000 BOE/day
Fourth quarter average crude oil and natural gas liquids production	47,000 - 49,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	26%
Operating expenses	$8.00/BOE (from $8.25/BOE)
Transportation costs	$4.00/BOE (from $4.15/BOE)
Cash G&A expenses	$1.35/BOE (from $1.40/BOE)

2020 Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(5.00)/bbl(2)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.60)/Mcf (from US$(0.45)/Mcf)

(1) Excluding transportation costs.
(2) Guidance is based on the continued operation of DAPL.

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)	2020	2019	2020	2019
Oil and natural gas sales	$ 239.9	$ 401.8	$ 680.8	$ 1,161.4
Less:				
Royalties	(48.0)	(82.9)	(138.7)	(233.6)
Production taxes	(13.6)	(23.6)	(36.7)	(59.6)
Operating expenses	(65.1)	(69.6)	(198.5)	(211.3)
Transportation costs	(32.2)	(39.0)	(101.5)	(107.1)
Netback before hedging	$ 81.0	$ 186.7	$ 205.4	$ 549.8
Cash gains/(losses) on derivative instruments	19.7	5.2	106.2	14.6
Netback after hedging	$ 100.7	$ 191.9	$ 311.6	$ 564.4

"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)	2020	2019	2020	2019
Cash flow from operating activities	$ 137.0	$ 159.8	$ 350.3	$ 505.8
Asset retirement obligation expenditures	1.9	2.9	13.0	8.8
Changes in non-cash operating working capital	(55.8)	12.6	(97.0)	15.5
Adjusted funds flow	$ 83.1	$ 175.3	$ 266.3	$ 530.1

"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)	2020	2019	2020	2019
Adjusted funds flow	$ 83.1	$ 175.3	$ 266.3	$ 530.1
Capital spending	(35.3)	(151.5)	(239.1)	(519.5)
Free cash flow	$ 47.8	$ 23.8	$ 27.2	$ 10.6

"Adjusted net income/(loss)" 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/(loss) is calculated as net income/(loss) adjusted for unrealized derivative instrument gain/loss, asset impairment, unrealized foreign exchange gain/loss, the tax effect of these items, goodwill impairment, the impact of statutory changes to the Company's corporate tax rate, and the valuation allowance on our deferred income tax assets. There was no asset or goodwill impairments for the three and nine months ended September 30, 2019.

Calculation of Adjusted Net Income	**Three months ended September 30,**		**Nine months ended September 30,**	
($ millions)	**2020**	**2019**	**2020**	**2019**
Net income/(loss)	$ (112.8)	$ 65.1	$ (719.2)	$ 169.4
Unrealized derivative instrument (gain)/loss	19.2	(14.9)	(13.3)	52.0
Asset impairment	256.8	—	683.6	—
Unrealized foreign exchange (gain)/loss	0.5	8.6	(0.9)	(25.0)
Tax effect on above items	(72.2)	3.1	(175.2)	(14.0)
Goodwill impairment	—	—	202.8	—
Income tax rate adjustment on deferred taxes	—	—	—	26.3
Valuation allowance on deferred taxes	(73.8)	—	19.8	—
Adjusted net income/(loss)	$ 17.7	$ 61.9	$ (2.4)	$ 208.7

"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)	**2020**	**2019**	**2020**	**2019**
Dividends	$ 6.7	$ 6.8	$ 20.0	$ 21.0
Capital, office expenditures and line fill	36.2	154.4	242.8	530.7
Sub-total	$ 42.9	$ 161.2	$ 262.8	$ 551.7
Adjusted funds flow	$ 83.1	$ 175.3	$ 266.3	$ 530.1
Adjusted payout ratio (%)	52%	92%	99%	104%

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

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	**September 30, 2020**
Net income/(loss)	$ (1,148.3)
Add:	
Goodwill impairment	653.9
Interest	31.2
Current and deferred tax expense/(recovery)	(126.3)
DD&A and asset impairment	1,019.0
Other non-cash charges(2)	20.2
Adjusted EBITDA	$ 449.7

(1) Balances above at September 30, 2020 include the nine months ended September 30, 2020 and the fourth quarter of 2019.
(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", "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, 2020, 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, 2020 and ended September 30, 2020 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: expectations regarding the duration and overall impact of COVID-19, expected capital spending levels in 2020 and impact thereof on our production levels and land holdings; expected production volumes and updated 2020 and fourth quarter production guidance; expected operating strategy in 2020, including the effect of Enerplus' production curtailment on its properties, operations and financial position; the proportion of our anticipated oil and gas production that is hedged and the expected 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, our commodity risk management program in 2020 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating, transportation and cash G&A costs; potential future non-cash PP&E impairments, as well as relevant factors that may affect such impairment; 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; Enerplus' costs reduction initiatives and the expected cost savings therefrom in 2020; 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; the continued ability to operate DAPL and lack of court order restricting its operation, that our development plans will achieve the expected results; that lack of adequate infrastructure and/or low commodity price environment will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to comply with our debt covenants; the availability of third party services; and the extent of our liabilities. In addition, our expected 2020 capital expenditures and operating strategy described in this MD&A is based on the rest of the year prices and exchange rate of: a WTI price of US$37.24/bbl, a NYMEX price of US$2.82/Mcf, and a USD/CDN exchange rate of 1.33. 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. Current conditions, economic and otherwise, render assumptions, although reasonable when made, subject to greater uncertainty.

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 instability, or further deterioration, in global economic and market environment, including from COVID-19; continued low commodity prices environment or further decline and/or 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; the legal proceedings in connection with DAPL; 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 this MD&A, our Annual Information Form, our Annual MD&A and Form 40-F as at December 31, 2019).

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.