Exhibit 99.1

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

The following discussion and analysis of financial results is dated May 7, 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 months ended March 31, 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 and global excess supply of crude oil have created unprecedented market volatility and significant challenges for our industry. Government and health authorities' efforts to slow the spread of the virus have resulted in a sudden contraction of the global economy, causing a significant reduction in crude oil demand. At the same time, the initial failure of the Organization of the Petroleum Exporting Countries Plus ("OPEC+") nations to agree on production restrictions in early March led to a dramatic increase in global crude oil supply. This resulted in a decrease of approximately 50% in WTI benchmark prices in March to US$30.45/bbl compared to average December prices of US$59.80/bbl. These events also led to indiscriminate downward pressure on energy equities, resulting in a 78% decline in our share price at March 31, 2020 compared to December 31, 2019. In response, on April 22, 2020, we issued a news release withdrawing our 2020 corporate guidance provided in the news release dated March 16, 2020 and included in our Annual MD&A dated February 20, 2020. We will continue to reassess our ability to reasonably estimate and provide annual guidance and plan to provide additional operational updates to our investors during this period of heightened volatility.

Despite the challenging market conditions, we are focused on preserving our balance sheet and maintaining our liquidity. At March 31, 2020, total debt net of cash was $514.6 million, including senior notes of $656.7 million and cash on hand of $142.1 million, and our net debt to adjusted funds flow ratio was 0.8x. At March 31, 2020 and as of the date of this MD&A, we were undrawn on our US$600 million bank credit facility and we are compliant with all debt covenants.

Production for the first quarter of 2020 averaged 98,209 BOE/day, a 9% decrease compared to production of 107,436 BOE/day in the fourth quarter of 2019. Production decreased in North Dakota as expected due to modest capital spending in the fourth quarter, primarily focused on drilling activity. Natural gas production also decreased with limited capital spending in both the fourth quarter of 2019 and the first quarter of 2020. Natural gas volumes were further impacted by our decision during the first quarter to shut-in, abandon and reclaim our non-core natural gas assets at Tommy Lakes in Canada.

Beginning in April 2020, we have temporarily shut-in select wells across the Williston basin and our Canadian waterfloods to protect against selling crude oil at negative margins. Our April production was approximately 91,500 BOE/day, including 49,700 bbls/day of crude oil and natural gas liquids, exceeding our expected April production of 88,000 BOE/day including 47,000 bbls/day of crude oil and natural gas liquids. In May, we began curtailing further production. Currently, we estimate that approximately 25% of our crude oil and natural gas liquids volumes are curtailed, which excludes our recently completed seven-well pad in North Dakota that we have chosen not to produce until oil prices improve. Based on current quarter regional pricing dynamics, we do not anticipate curtailing production beyond current levels through the rest of the second quarter.

Capital activity and production expectations for our Marcellus natural gas position remain unchanged relative to our original 2020 plans. We expect Marcellus production to average approximately 185 MMcf/day to 200 MMcf/day for the remainder of the year.

Our Bakken crude oil price differential widened to US$5.26/bbl below WTI during the first quarter, compared to US$4.40/bbl below WTI in the fourth quarter of 2019, due to regional production remaining above pipeline takeaway capacity. We have fixed physical differential sales agreements in place for the remainder of 2020 for approximately 13,000 bbls/day of crude oil in North Dakota at an estimated price of WTI less US$5.00/bbl. Our Marcellus natural gas price differential narrowed to US$0.38/Mcf below NYMEX during the first quarter from US$0.63/Mcf below NYMEX in the fourth quarter of 2019 due to increased seasonal demand in the region. We continue to expect our Marcellus natural gas price differential to average US$0.45/Mcf below NYMEX in 2020.

We expect our commodity hedging program to protect a significant portion of our cash flow from operating activities and adjusted funds flow. At March 31, 2020, our crude oil commodity derivative contracts were in a net asset position of $108.4 million and we expect our commodity hedging position to provide full year gains of approximately $150 million based on recent forward strip oil prices. As of May 7, 2020, we had approximately 24,800 bbls/day of crude oil hedged for the remainder of 2020.

Capital expenditures totaled $163.6 million during the first quarter, with approximately 95% of capital spending directed to crude oil properties in North Dakota, the DJ Basin and the Canadian waterfloods.

We have reduced our expected capital spending to $300 million through the suspension of all further drilling and completions activity in North Dakota, efficiency improvements and the deferral of certain non-operated oil activity. In total, we have reduced our 2020 capital spending budget by approximately 45% from our original guidance range of $520 million to $570 million.

Operating costs for the quarter were $79.0 million, or $8.84/BOE, compared to $79.5 million, or $8.05/BOE, in the fourth quarter of 2019 mainly due to lower production in the first quarter of 2020. We have reduced our expected average annual operating costs to $8.25/BOE from our previous guidance of $8.50/BOE through further project prioritization and service cost reductions.

We reported net income of $2.9 million in the first quarter of 2020 compared to a net loss of $429.1 million in the fourth quarter of 2019. The increase was primarily the result of a $451.1 million non-cash goodwill impairment recorded in the fourth quarter of 2019 and a $131.3 million gain on commodity derivative instruments recorded in the first quarter of 2020. Net income in the first quarter was also impacted by a $93.6 million valuation allowance recorded against a portion of our Canadian deferred income tax assets.

During the first quarter of 2020, cash flow from operations decreased to $122.7 million, compared to $188.5 million in the fourth quarter of 2019, and adjusted funds flow decreased to $113.2 million from $178.9 million in the same respective periods. The decreases were the result of lower production and a decline in realized prices, offset by higher realized commodity derivative gains in the first quarter.

During the quarter, 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 deterioration in market conditions, we have suspended our share repurchase program to prioritize our financial strength and liquidity. We plan to renew our NCIB in due course and recommence our share repurchase program when market conditions improve.

RESULTS OF OPERATIONS

Production

Daily production for the first quarter averaged 98,209 BOE/day, a decrease of 9% compared to average production of 107,436 BOE/day in the fourth quarter of 2019. Crude oil and natural gas liquids production decreased by 5,456 bbls/day primarily due to the timing of our 2019 capital program, with lower capital spending in the fourth quarter. Natural gas production decreased 8% to 262,913 Mcf/day in the first quarter of 2020 from 285,537 Mcf/day in the fourth quarter of 2019 due to limited capital activity in the Marcellus and our decision to shut-in, abandon and reclaim Tommy Lakes, a Canadian asset with approximately 1,600 BOE/day (90% natural gas) of average annual production.

For the three months ended March 31, 2020, total production increased by 11%, when compared to the same period in 2019. The increase in production was primarily due to a 29% increase in U.S. crude oil and natural gas liquids production as a result of our continued capital investment in North Dakota.

Our crude oil and natural gas liquids weighting increased to 55% in the first quarter of 2020 from 51% for the same period in 2019.

Average daily production volumes for the three months ended March 31, 2020 and 2019 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2020**	**2019**	**% Change**
Crude oil (bbls/day)	49,044	41,105	19%
Natural gas liquids (bbls/day)	5,346	4,383	22%
Natural gas (Mcf/day)	262,913	258,568	2%
Total daily sales (BOE/day)	98,209	88,583	11%

As announced in our April 22, 2020 news release, we have withdrawn our annual production guidance due to ongoing uncertainty in market conditions. Daily production in April was modestly impacted by shut-ins, with monthly average production of approximately 91,500 BOE/day, including 49,700 bbls/day of crude oil and natural gas liquids, exceeding our expected April average production of 88,000 BOE/day including 47,000 bbls/day of crude oil and natural gas liquids. In May, we began curtailing further production. Currently, we estimate that approximately 25% of our crude oil and natural gas liquids volumes are curtailed, which excludes our recently completed seven-well pad in North Dakota that we have chosen not to produce until oil prices improve. Based on current regional pricing dynamics, we do not anticipate curtailing production beyond current levels through the rest of the second quarter.

Capital activity and production expectations for our Marcellus natural gas position remain unchanged relative to our original 2020 plans. We expect Marcellus production to average approximately 185 MMcf/day to 200 MMcf/day for the remainder 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 three months ended March 31, 2020 and 2019 and other periods indicated:

Pricing (average for the period)	**Q1 2020**	**Q4 2019**	**Q3 2019**	**Q2 2019**	**Q1 2019**
Benchmarks					
WTI crude oil (US$/bbl)	$ 46.17	$ 56.96	$ 56.45	$ 59.81	$ 54.90
Brent (ICE) crude oil (US$/bbl)	50.96	62.51	62.00	68.32	63.90
NYMEX natural gas – last day (US$/Mcf)	1.95	2.50	2.23	2.64	3.15
USD/CDN average exchange rate	1.34	1.32	1.32	1.34	1.33
USD/CDN period end exchange rate	1.41	1.30	1.32	1.31	1.33
Enerplus selling price(1)					
Crude oil ($/bbl)	$ 51.30	$ 67.23	$ 67.76	$ 74.42	$ 66.56
Natural gas liquids ($/bbl)	12.72	18.28	5.97	17.96	19.15
Natural gas ($/Mcf)	2.08	2.50	2.13	2.63	4.38
Average differentials					
Bakken DAPL – WTI (US$/bbl)	$ (5.34)	$ (5.59)	$ (2.97)	$ (2.36)	$ (2.93)
Brent (ICE) – WTI (US$/bbl)	4.79	5.55	5.55	8.51	9.00
MSW Edmonton – WTI (US$/bbl)	(7.58)	(5.37)	(4.66)	(4.63)	(4.85)
WCS Hardisty – WTI (US$/bbl)	(20.53)	(15.83)	(12.24)	(10.67)	(12.29)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.39)	(0.70)	(0.48)	(0.43)	(0.22)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.41	(0.11)	(0.35)	(0.31)	1.67
Enerplus realized differentials(1)(2)					
Bakken crude oil – WTI (US$/bbl)	$ (5.26)	$ (4.40)	$ (3.61)	$ (3.00)	$ (3.25)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.38)	(0.63)	(0.44)	(0.57)	0.13
Canada crude oil – WTI (US$/bbl)	(17.77)	(14.80)	(13.50)	(9.99)	(10.42)

(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 first quarter of 2020 averaged $51.30/bbl, a decrease of 24% compared to the fourth quarter of 2019 due to weaker benchmark prices and wider realized price differentials for our production. Benchmark WTI prices fell by 19% over the same period due to the combined impact of the global demand destruction resulting from the COVID-19 pandemic and the dramatic increase in the supply of Russian and Saudi Arabian crude oil in the markets after the OPEC+ nations failed to agree on production restrictions in early March 2020.

Our realized Bakken price differential weakened by US$0.86/bbl during the quarter to average US$5.26/bbl below WTI due to regional production remaining above pipeline takeaway capacity and a lower volume of crude oil sold under fixed price differential contracts compared to the fourth quarter of 2019. 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. A portion of our physical sales are directly tied to the spread between Brent and WTI crude oil prices. That differential narrowed by US$0.76/bbl, during the quarter, which resulted in a weaker realized price for a portion of our production. For the remainder of 2020, we have fixed physical differential sales agreements in North Dakota for approximately 13,000 bbls/day at an estimated price of WTI less US$5.00/bbl.

Our realized price differential for Canadian crude oil production widened by US$2.97/bbl compared to the fourth quarter of 2019, which was in line with changes to the underlying benchmark prices for Canadian crude oil.

Our realized sales price for natural gas liquids averaged $12.72/bbl during the first quarter of 2020, a 30% decrease compared to the previous quarter mainly due to the decrease in the WTI benchmark price, with a significant portion of our natural gas liquids contracts tied to WTI pricing.

NATURAL GAS

Our realized natural gas sales price decreased by 17% during the quarter to average $2.08/Mcf. NYMEX benchmark prices fell 22% over the same period due to warmer than average weather across the U.S. resulting in significant price weakness throughout the first quarter. Our realized Marcellus sales price differential averaged US$0.38/Mcf below NYMEX during the quarter, compared to US$0.63/Mcf in the fourth quarter of 2019, reflecting seasonal strength in local market price differentials over the period. A significant portion of our production receives prices reflecting market conditions south of New York. Prices for Transco Zone 6 Non-New York averaged US$0.41/Mcf over NYMEX in the first quarter, and this seasonal strength helped improve our overall realized price for our Marcellus production. We continue to expect our Marcellus natural gas price differential to average US$0.45/Mcf below NYMEX in 2020.

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 weakened significantly near the end of the first quarter 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 Canadian dollar weakened to 1.41 USD/CDN at March 31, 2020, compared to 1.30 USD/CDN at December 31, 2019. The average exchange rate during the first quarter remained consistent compared to the same period of the prior year, averaging 1.34 USD/CDN compared to 1.33 USD/CDN in the first quarter of 2019.

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 May 7, 2020, we have hedged 24,800 bbls/day of crude oil for the remainder of 2020. Our crude oil hedges are a mix of swaps, put spreads and three way collars. The put spreads and three way collars provide us with exposure to significant upwards 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. 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.

The following is a summary of our financial contracts in place at May 7, 2020:

	WTI Crude Oil (US$/bbl)		
	Apr 1, 2020 – Jun 30, 2020	**Jul 1, 2020 – Sep 30, 2020**	**Oct 1, 2020 – Dec 31, 2020**
Swaps			
Volume (bbls/day)	9,500	7,000	—
Sold Swaps	$ 57.37	$ 36.02	—
Put Spreads[(1)]			
Volume (bbls/day)	16,000	16,000	16,000
Sold Puts[(2)]	$ 46.88	$ 46.88	$ 46.88
Purchased Puts	$ 57.50	$ 57.50	$ 57.50
Three Way Collars[(1)]			
Volume (bbls/day)	—	5,000	5,000
Sold Puts	—	$ 48.00	$ 48.00
Purchased Puts	—	$ 56.25	$ 56.25
Sold Calls	—	$ 65.00	$ 65.00

(1) The total average deferred premium spent on our outstanding hedges is US$1.67/bbl from April 1, 2020 to December 31, 2020.
(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 March 31,**	
($ millions)	**2020**	**2019**
Cash gains/(losses):		
Crude oil	$ 33.0	$ (2.0)
Natural gas	—	12.5
Total cash gains/(losses)	$ 33.0	$ 10.5
Non-cash gains/(losses):		
Crude oil	$ 98.3	$ (86.9)
Natural gas	—	(8.5)
Total non-cash gains/(losses)	$ 98.3	$ (95.4)
Total gains/(losses)	$ 131.3	$ (84.9)

	Three months ended March 31,	
(Per BOE)	**2020**	**2019**
Total cash gains/(losses)	$ 3.69	$ 1.32
Total non-cash gains/(losses)	11.01	(11.97)
Total gains/(losses)	$ 14.70	$ (10.65)

We realized cash gains of $33.0 million on our crude oil contracts during the first quarter of 2020, compared to realized cash losses of $2.0 million for the same period in 2019. Cash gains on crude oil contracts in the first quarter of 2020 were primarily due to prices falling below the swap level and the put strike price on our put spreads and three way collars. Our natural gas contracts were settled in the fourth quarter of 2019 and there were no natural gas derivative contracts outstanding during the first quarter of 2020. In comparison, we realized cash gains of $12.5 million on our natural gas contracts during the first quarter of 2019.

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 March 31, 2020, the fair value of crude oil contracts was in a net asset position of $108.4 million. For the three months ended March 31, 2020, the change in the fair value of our crude oil contracts resulted in a gain of $98.3 million, compared to a $86.9 million loss during the same period in 2019. We had no natural gas derivative contracts outstanding at March 31, 2020. In comparison, we recorded a non-cash loss of $8.5 million on our natural gas contracts during the first quarter of 2019.

Revenues

	Three months ended March 31,	
($ millions)	**2020**	**2019**
Oil and natural gas sales	$ 285.6	$ 356.4
Royalties	(57.5)	(68.9)
Oil and natural gas sales, net of royalties	$ 228.1	$ 287.5

Oil and natural gas sales, net of royalties, for the three months ended March 31, 2020 were $228.1 million, a decrease of 21% from the same period in 2019. The decrease in revenue was a result of lower realized prices partially offset by higher production volumes when compared to the same period in 2019. See Note 11 to the Interim Financial Statements for further detail.

Royalties and Production Taxes

	Three months ended March 31,	
($ millions, except per BOE amounts)	**2020**	**2019**
Royalties	$ 57.5	$ 68.9
Per BOE	$ 6.43	$ 8.65
Production taxes	$ 15.4	$ 14.6
Per BOE	$ 1.73	$ 1.83
Royalties and production taxes	$ 72.9	$ 83.5
Per BOE	$ 8.16	$ 10.48
Royalties and production taxes (% of oil and natural gas sales)	26%	23%

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 months ended March 31, 2020 were $72.9 million, a decrease of 13% from the same period in 2019. The decrease was primarily due to lower realized prices, which more than offset the increase in production.

Operating Expenses

	Three months ended March 31,	
($ millions, except per BOE amounts)	2020	2019
Cash operating expenses	$ 79.0	$ 69.8
Per BOE	$ 8.84	$ 8.75

For the three months ended March 31, 2020, operating expenses were $79.0 million or $8.84/BOE, an increase of $9.2 million or $0.09/BOE from the same period in 2019. The increase was mainly due to higher crude oil and natural gas liquids production, with our liquids weighting increasing to 55% from 51% over the same period.

As announced in our April 22, 2020 news release, we have reduced our expected average annual operating costs to $8.25/BOE from previous guidance of $8.50/BOE due to expected cost savings.

Transportation Costs

	Three months ended March 31,	
($ millions, except per BOE amounts)	2020	2019
Transportation costs	$ 35.3	$ 31.3
Per BOE	$ 3.95	$ 3.92

For the three months ended March 31, 2020, transportation costs were $35.3 million or $3.95/BOE, an increase of $4.0 million from the same period in 2019. The increase was primarily due to growth in U.S. crude oil and natural gas liquids production over the same period.

Netbacks

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Three months ended March 31, 2020		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	59,226 BOE/day	233,898 Mcfe/day	98,209 BOE/day
Netback(1) $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 44.46	$ 2.16	$ 31.96
Royalties and production taxes	(11.94)	(0.40)	(8.16)
Cash operating expenses	(13.35)	(0.33)	(8.84)
Transportation costs	(2.92)	(0.92)	(3.95)
Netback before hedging	$ 16.25	$ 0.51	$ 11.01
Cash hedging gains/(losses)	6.12	—	3.69
Netback after hedging	$ 22.37	$ 0.51	$ 14.70
Netback before hedging ($ millions)	$ 87.6	$ 10.8	$ 98.4
Netback after hedging ($ millions)	$ 120.6	$ 10.8	$ 131.4

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

	Three months ended March 31, 2019		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	48,909 BOE/day	238,044 Mcfe/day	88,583 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 59.51	$ 4.41	$ 44.70
Royalties and production taxes	(14.92)	(0.83)	(10.48)
Cash operating expenses	(13.96)	(0.39)	(8.75)
Transportation costs	(2.75)	(0.90)	(3.92)
Netback before hedging	$ 27.88	$ 2.29	$ 21.55
Cash hedging gains/(losses)	(0.45)	0.59	1.32
Netback after hedging	$ 27.43	$ 2.88	$ 22.87
Netback before hedging ($ millions)	$ 122.7	$ 49.1	$ 171.8
Netback after hedging ($ millions)	$ 120.8	$ 61.5	$ 182.3

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

Total netbacks before hedging for the three months ended March 31, 2020 were lower compared to the same period in 2019 primarily due to weaker realized prices.

For the three months ended March 31, 2020, our crude oil properties accounted for 89% of our total netback before hedging, compared to 71% during the same period 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 to the Interim Financial Statements for further details.

	Three months ended March 31,	
($ millions)	**2020**	**2019**
Cash:		
G&A expense	$ 12.2	$ 12.3
Share-based compensation expense	(2.7)	1.3
Non-Cash:		
Share-based compensation expense	7.7	8.1
Equity swap loss/(gain)	1.9	(0.1)
G&A expense	0.1	0.1
Total G&A expenses	$ 19.2	$ 21.7

	Three months ended March 31,	
(Per BOE)	**2020**	**2019**
Cash:		
G&A expense	$ 1.37	$ 1.55
Share-based compensation expense	(0.31)	0.17
Non-Cash:		
Share-based compensation expense	0.86	1.01
Equity swap loss/(gain)	0.21	(0.01)
G&A expense	0.01	0.01
Total G&A expenses	$ 2.14	$ 2.73

Cash G&A expenses for the three months ended March 31, 2020 were $12.2 million, or $1.37/BOE, compared to $12.3 million, or $1.55/BOE, for the same period in 2019. Cash G&A expenses were consistent with the same period in 2019 but decreased on a per BOE basis due to higher production.

During the first quarter of 2020, we reported a cash SBC recovery of $2.7 million compared to an expense of $1.3 million for the same period in 2019. The recovery was due to the decrease in our share price on outstanding deferred share units. Non-cash SBC expense for the three months ended March 31, 2020 was $7.7 million, or $0.86/BOE, a decrease from an expense of $8.1 million, or $1.01/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 first quarter of 2020, we recorded a mark-to-market loss of $1.9 million on these contracts, compared to a gain of $0.1 million in the same period in 2019.

Subsequent to the quarter, we reduced cash compensation for our Board of Directors, executives and employees. Including additional non-salary cost reductions, we anticipate cash G&A expenses will be approximately $5 million lower than our original 2020 budget.

Interest Expense

For the three months ended March 31, 2020, we recorded total interest expense of $8.9 million, compared to $8.4 million for the same period in 2019. The increase in interest expense in the first quarter of 2020 was primarily due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest expense.

At March 31, 2020, we were undrawn on our US$600 million 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 March 31,	
($ millions)	2020	2019
Realized foreign exchange (gain)/loss:		
Foreign exchange (gain)/loss on settlements	$ (0.1)	$ (0.1)
Translation of U.S. dollar cash held in Canada (gain)/loss	(3.1)	5.2
Unrealized foreign exchange (gain)/loss	(2.4)	(17.1)
Total foreign exchange (gain)/loss	$ (5.6)	$ (12.0)
USD/CDN average exchange rate	1.34	1.33
USD/CDN period end exchange rate	1.41	1.33

For the three months ended March 31, 2020, we recorded a foreign exchange gain of $5.6 million compared to $12.0 million for the same period in 2019. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies along with 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 working capital held in Canada at each period end.

Effective January 1, 2020, we have designated US$467.0 million of 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 March 31, 2020, Other Comprehensive Income/(Loss) included an unrealized loss of $50.1 million on our outstanding U.S. dollar denominated senior notes (March 31, 2019 – $14.1 million unrealized foreign exchange gain included in net income). The unrealized foreign exchange gain of $2.4 million at March 31, 2020 related to the translation of U.S. dollar denominated working capital held in Canada. See Note 3(a) to the Interim Financial Statements for further details.

Capital Investment

	Three months ended March 31,	
($ millions)	2020	2019
Capital spending(1)	$ 163.6	$ 160.8
Office capital(1)	1.9	1.1
Line fill	—	5.1
Sub-total	165.5	167.0
Property and land acquisitions	$ 2.3	$ 3.0
Property divestments	(5.6)	(0.5)
Sub-total	(3.3)	2.5
Total	$ 162.2	$ 169.5

(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 months ended March 31, 2020 totaled $163.6 million compared to $160.8 million for the same period in 2019. During the first quarter of 2020, we spent $145.0 million on our U.S. crude oil properties, $6.8 million on our Marcellus natural gas assets and $11.7 million on our Canadian waterflood properties.

During the first quarter, we completed $2.3 million in property and land acquisitions, which included minor acquisitions of leases and undeveloped land, compared to $3.0 million for the same period in 2019. Property divestments for the three months ended March 31, 2020 were $5.6 million compared to $0.5 million for the same period in 2019.

As announced on April 22, 2020, we have reduced our expected 2020 annual capital spending by an additional $25 million to $300 million to further preserve our balance sheet and liquidity position as a result of low crude oil prices. In total, we have decreased our 2020 capital budget by approximately 45% from our original guidance range.

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

	Three months ended March 31,	
($ millions, except per BOE amounts)	**2020**	**2019**
DD&A expense	$ 95.2	$ 75.9
Per BOE	$ 10.65	$ 9.52

DD&A of property, plant and equipment (“PP&E”) is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2020, DD&A increased compared to the same period in 2019 as a result of additional U.S. production with higher depletion rates.

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. There have been no PP&E impairments recorded in the current or prior year. See Note 6 to the Interim Financial Statements for trailing twelve month prices.

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. We expect the twelve month trailing crude oil prices to decline further in 2020, impacting the ceiling value and increasing the 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. The portion of goodwill that relates to U.S. operations fluctuates due to changes in foreign exchange rates. 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.

There was no goodwill impairment recorded during the first quarter of 2020 or the same period of the prior year. At March 31, 2020, we reported $210.0 million of goodwill related to our U.S. reporting unit. There is a risk of future goodwill impairments if commodity prices continue to weaken or there is a downward revision to reserves. 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.

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 $146.1 million at March 31, 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 months ended March 31, 2020, asset retirement obligation settlements were $10.8 million compared to $5.4 million during the same period 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 March 31, 2020, our total lease liability was $51.4 million. In addition, ROU assets of $46.6 million were recorded, which equate to our lease liabilities less lease incentives. See Note 10 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended March 31,	
($ millions)	**2020**	**2019**
Current tax expense/(recovery)	$ —	$ (5.5)
Deferred tax expense/(recovery)	109.4	(17.9)
Total tax expense/(recovery)	$ 109.4	$ (23.4)

We recorded a total tax expense of $109.4 million for the period ending March 31, 2020, compared to a recovery of $23.4 million for the same period in 2019. The expense in 2020 relates to higher income in the first quarter of 2020, primarily resulting from unrealized commodity derivative gains and a valuation allowance of $93.6 million recorded against a portion of our Canadian deferred income tax assets. No valuation allowance was recorded against our U.S. deferred income tax assets.

We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will not be realized. We have considered available positive and negative evidence, including future taxable income and reversing existing temporary differences, in making this assessment. This assessment is primarily the result of projecting future taxable income using total proved and probable reserves at forecast average prices and costs. There is a risk of additional valuation allowances in future periods if commodity prices weaken or other evidence indicates that more of our deferred income tax assets will not be realized. 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. After recording the valuation allowance, our overall net deferred income tax asset was $273.0 million at March 31, 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 March 31, 2020, our senior debt to adjusted EBITDA ratio was 1.0x and our net debt to adjusted funds flow ratio was 0.8x. 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.

At March 31, 2020, we had $142.1 million of cash on hand and an undrawn US$600 million bank credit facility. Total debt net of cash at March 31, 2020, was $514.6 million, an increase of 13% compared to $455.0 million at December 31, 2019. The increase when compared to December 31, 2019 was primarily a result of the impact of a weaker Canadian dollar at March 31, 2020 on our U.S. dollar denominated senior notes. We have near-term debt maturities of US$82 million in senior notes due in May and June 2020, which we intend to repay with cash on hand, and our remaining maturities extend to 2026.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 152% for the three months ended March 31, 2020, compared to 103% for the same period in 2019.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, increased to $270.9 million at March 31, 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 expect to be able to meet our financial commitments, as disclosed under “Commitments” in the Annual MD&A.

During the first quarter, 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 current environment, we have chosen not to renew our NCIB in order to conserve capital and preserve our balance sheet strength. We plan to renew our NCIB in due course and recommence our share repurchase program when market conditions improve.

At March 31, 2020, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. We expect to manage our business within these financial ratios during 2020; however, current commodity prices have created a significant level of uncertainty which may challenge this expectation. 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 March 31, 2020:

Covenant Description		March 31, 2020
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.0x
Total debt to adjusted EBITDA (1)	4.0x	1.0x
Total debt to capitalization	55%	21%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.0x
Senior debt to consolidated present value of total proved reserves(3)	60%	21%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	19.2x

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 March 31, 2020 was $125.3 million and $659.4 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

	Three months ended March 31,	
($ millions, except per share amounts)	2020	2019
Dividends to shareholders(1)	$ 6.7	$ 7.2
Per weighted average share (Basic)	$ 0.03	$ 0.03

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

During the three months ended March 31, 2020, we reported total dividends of $6.7 million or $0.03 per share compared to $7.2 million or $0.03 per share for the same period in 2019. Dividends to shareholders have decreased compared to the same period 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

	Three months ended March 31, 2020	2019
Share capital ($ millions)	$ 3,097.2	$ 3,317.9
Common shares outstanding (thousands)	222,564	238,243
Weighted average shares outstanding – basic (thousands)	222,357	238,922
Weighted average shares outstanding – diluted (thousands)	223,300	241,298

For the three months ended March 31, 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 three months ended March 31, 2020, the Company 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 – 1,732,038; $19.8 million). Of the amount paid, $4.7 million was charged to share capital and $2.2 million was credited to accumulated deficit (2019 – $24.1 million; $4.3 million). Given the current environment, we chose not to renew our NCIB in order to preserve capital and maintain our balance sheet strength and liquidity.

At May 7, 2020, we had 222,563,267 common shares outstanding. In addition, an aggregate of 6,905,615 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 March 31, 2020			Three months ended March 31, 2019		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	7,836	41,208	49,044	8,998	32,107	41,105
Natural gas liquids (bbls/day)	710	4,636	5,346	984	3,399	4,383
Natural gas (Mcf/day)	14,913	248,000	262,913	24,348	234,220	258,568
Total average daily production (BOE/day)	11,032	87,177	98,209	14,040	74,543	88,583
Pricing(2)						
Crude oil (per bbl)	$ 38.78	$ 53.68	$ 51.30	$ 59.07	$ 68.66	$ 66.56
Natural gas liquids (per bbl)	23.90	11.01	12.72	35.89	14.30	19.15
Natural gas (per Mcf)	2.18	2.07	2.08	4.64	4.35	4.38
Capital Expenditures						
Capital spending	$ 11.8	$ 151.8	$ 163.6	$ 17.5	$ 143.3	$ 160.8
Acquisitions	1.1	1.2	2.3	1.0	2.0	3.0
Divestments	—	(5.6)	(5.6)	(0.1)	(0.4)	(0.5)
Netback(3) **Before Hedging**						
Oil and natural gas sales	$ 32.8	$ 252.8	$ 285.6	$ 61.8	$ 294.6	$ 356.4
Royalties	(5.7)	(51.8)	(57.5)	(8.9)	(60.0)	(68.9)
Production taxes	(0.3)	(15.1)	(15.4)	(0.6)	(14.0)	(14.6)
Cash operating expenses	(17.5)	(61.5)	(79.0)	(21.0)	(48.8)	(69.8)
Transportation costs	(2.1)	(33.2)	(35.3)	(2.7)	(28.6)	(31.3)
Netback before hedging	$ 7.2	$ 91.2	$ 98.4	$ 28.6	$ 143.2	$ 171.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (131.3)	$ —	$ (131.3)	$ 84.9	$ —	$ 84.9
Total G&A(4)	(0.3)	19.5	19.2	13.2	8.5	21.7
Current income tax expense/(recovery)	—	—	—	—	(5.5)	(5.5)

(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
2020				
First Quarter	$ 228.1	$ 2.9	$ 0.01	$ 0.01
Total 2020	$ 228.1	$ 2.9	$ 0.01	$ 0.01
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, decreased during the first quarter of 2020 compared to the fourth quarter of 2019 due to lower realized prices. Net income increased to $2.9 million during the first quarter of 2020 compared to a net loss of $429.1 million in the fourth quarter of 2019. The increase was primarily the result of a $451.1 million non-cash goodwill impairment recorded in the fourth quarter of 2019 and a $131.3 million gain on commodity derivative instruments recorded in the first quarter of 2020. Net income in the first quarter of 2020 was also impacted by a $93.6 million valuation allowance recorded against a portion of our Canadian deferred income tax assets.

Oil and natural gas sales, net of royalties, in 2019 were essentially flat when compared to 2018 due to lower realized commodity prices, 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 and a loss on commodity derivative instruments of $66.1 million compared to a gain of $88.2 million recorded in 2018.

RISK FACTORS AND RISK MANAGEMENT

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

The recent COVID-19 pandemic and governmental authorities response thereto has resulted in, and may continue 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; business closures and travel bans; an overall slowdown in the global economy; and political and economic instability. In particular, the COVID-19 pandemic has resulted in, and may continue 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 as a result of the failure by OPEC+ nations to set and maintain production restrictions in early March 2020 and decreased global demand due to the COVID-19 pandemic, have caused significant weakness and volatility in commodity prices. With the rapid spread of the COVID-19 pandemic and additional crude oil supply, the price of crude oil and other petroleum products has deteriorated significantly and, notwithstanding recent agreements among OPEC+ nations to reduce production levels, is expected to remain under pressure and be volatile. The overall result of these recent events and conditions could lead to a prolonged period of depressed prices for crude oil and natural gas. In response to the current decreased crude oil and natural gas prices, we have voluntarily shut-in certain production, and a prolonged period of decreased prices may result in further curtailments or shutting-in of production, 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, such impact may be adverse and could result, among other things, in PP&E, goodwill or deferred tax asset impairment, or exceeding our debt covenants. See disclosure under "Impairment", “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.

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 March 31,**	
($ millions)	**2020**	**2019**
Oil and natural gas sales	$ 285.6	$ 356.4
Less:		
Royalties	(57.5)	(68.9)
Production taxes	(15.4)	(14.6)
Cash operating expenses	(79.0)	(69.8)
Transportation costs	(35.3)	(31.3)
Netback before hedging	$ 98.4	$ 171.8
Cash gains/(losses) on derivative instruments	33.0	10.5
Netback after hedging	$ 131.4	$ 182.3

"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 March 31,**	
($ millions)	**2020**	**2019**
Cash flow from operating activities	$ 122.7	$ 109.0
Asset retirement obligation expenditures	10.8	5.4
Changes in non-cash operating working capital	(20.3)	54.4
Adjusted funds flow	$ 113.2	$ 168.8

"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 March 31,**	
($ millions)	**2020**	**2019**
Adjusted funds flow	$ 113.2	$ 168.8
Capital spending	(163.6)	(160.8)
Free cash flow	$ (50.4)	$ 8.0

"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 as well as the valuation allowance on our deferred income tax assets.

Calculation of Adjusted Net Income	**Three months ended March 31,**	
($ millions)	**2020**	**2019**
Net income/(loss)	$ 2.9	$ 19.2
Unrealized derivative instrument (gain)/loss	(96.4)	95.3
Unrealized foreign exchange (gain)/loss	(2.4)	(17.1)
Tax effect on above items	23.4	(24.9)
Valuation allowance on deferred income tax assets	93.6	—
Adjusted net income	$ 21.1	$ 72.5

"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 March 31,**			
($ millions)		**2020**		**2019**
Dividends	$	6.7	$	7.2
Capital, office expenditures and line fill		165.5		167.0
Sub-total	$	172.2	$	174.2
Adjusted funds flow	$	113.2	$	168.8
Adjusted payout ratio (%)		152%		103%

"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)		**March 31, 2020**
Net income/(loss)	$	(276.0)
Add:		
Goodwill impairment		451.1
Interest		34.4
Current and deferred tax expense/(recovery)		180.6
DD&A and asset impairment		376.1
Other non-cash charges(2)		(106.8)
Adjusted EBITDA	$	659.4

(1) Balances above at March 31, 2020 include the three months ended March 31, 2020 and the second, third and 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 March 31, 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 January 1, 2020 and ended March 31, 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: expected capital spending levels in 2020 and impact thereof on our production levels and land holdings; expected production volumes; expected operating strategy in 2020, including the proportion of Enerplus' production that may be curtailed and the effect of such curtailment on its properties, operations and financial position; 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, our commodity risk management program in 2020 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating costs; our anticipated shares repurchases under future normal course issuer bids; 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; expectations regarding repayment of our outstanding senior notes, including sources of funds therefor; 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; 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$22.80/bbl, a NYMEX price of US$2.23/Mcf, and a USD/CDN exchange rate of 1.40. 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; 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.