Exhibit 99.1

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

The following discussion and analysis of financial results is dated November 3, 2022 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") at and for the three and nine months ended September 30, 2022 and 2021 (the "Interim Financial Statements") and notes thereto;
- the audited consolidated financial statements of Enerplus at December 31, 2021 and 2020 and for the years ended December 31, 2021, 2020 and 2019; and
- the MD&A for the year ended December 31, 2021 (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 the Annual MD&A and "Risk Factors" in Enerplus' Annual Information Form for the year ended December 31, 2021 (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. Unless otherwise stated, all dollar amounts are presented in U.S. dollars. All prior period amounts have been restated to reflect the U.S. dollar as the reporting currency. Certain prior period amounts have been reclassified 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 crude 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. All prior period crude oil and natural gas sales have been restated to be presented net of royalties. Unless otherwise stated, all production volumes and realized product prices information is presented on a "net" basis (after deduction of royalty obligations plus the Company's royalty interests) consistent with U.S. oil and gas reporting standards and thus, 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. All references to "natural gas" in this MD&A include conventional natural gas and shale gas.

OVERVIEW

Production during the third quarter of 2022 averaged 107,808 BOE/day, an increase of 15% compared to average production of 94,142 BOE/day in the second quarter of 2022 with crude oil and natural gas liquids production increasing by 20% over the same period. The increase in production was due to strong well performance during the quarter. As a result, we are increasing our average annual production guidance for 2022 to 99,750 BOE/day to 101,000 BOE/day, including 61,500 bbls/day to 62,500 bbls/day of crude oil and natural gas liquids, from 97,500 BOE/day to 101,500 BOE/day, including 59,500 bbls/day to 62,500 bbls/day of crude oil and natural gas liquids. For the fourth quarter of 2022, we expect average production of 105,000 BOE/day to 110,000 BOE/day, including 64,000 bbls/day to 68,000 bbls/day of crude oil and natural gas liquids. The updated production guidance includes the impact of the two previously announced Canadian asset divestments.

During the nine months ended September 30, 2022, a total of $271.3 million was returned to shareholders through share repurchases and dividends. During the third quarter of 2022, we announced our intention to increase our expected 2022 return of capital to at least 60% of free cash flow[1] commencing in the second half of 2022 and continuing through 2023, an increase from 50% of free cash flow in the first half of 2022. We also previously announced an increase to the expected minimum return of capital level to $425 million for 2022. Subsequent to the quarter, the Board of Directors approved a 10% increase to the quarterly dividend to $0.055 per share, from $0.050 per share, beginning December 2022. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

On July 28, 2022, the Company announced it had entered into a definitive agreement to sell certain Canadian assets located in Alberta for total consideration of CDN$140 million, prior to closing adjustments. The total consideration comprises cash, common shares of purchaser, and an amortizing interest-bearing loan provided by Enerplus. Production from the assets is approximately 3,400 BOE/day (60% crude oil). The sale closed on October 31, 2022.

Subsequent to the quarter, on November 2, 2022, the Company announced it had entered into a definitive agreement to sell substantially all of its remaining Canadian assets located in Alberta and Saskatchewan for total consideration of CDN$245 million, prior to closing adjustments. The total consideration comprises cash of CDN$210 million and CDN$35 million in common shares of the purchaser. Production from the assets is approximately 3,000 BOE/day (99% crude oil). The sale is expected to close in December 2022.

Capital spending during the third quarter of 2022 was $114.5 million, compared to $132.9 million during the second quarter of 2022, with the majority of the spending focused on our U.S. crude oil properties. The decrease in capital spending was due to less drilling and completions activity during the third quarter of 2022. We are revising our annual capital spending guidance for 2022 to be $430 million from a range between $400 million to $440 million.

Bakken crude oil price differentials continued to trade above WTI due to excess pipeline capacity in the region, and strong physical prices for crude oil delivered to the U.S. Gulf Coast. Our realized Bakken crude oil price differential averaged $2.41/bbl above WTI during the third quarter of 2022, compared to $0.85/bbl above WTI during the second quarter of 2022. Given continued strength in Bakken crude oil price differentials and strong year-to-date realizations, we expect our 2022 realized Bakken crude oil price differential to average $1.25/bbl above WTI, compared to our previous guidance of $1.00/bbl above WTI.

Our realized Marcellus sales price differential widened compared to the previous quarter due to weaker regional prices in September as the market transitioned into the lower-demand shoulder season. Our differential in the third quarter of 2022 averaged $0.99/Mcf below NYMEX, compared to $0.59/Mcf below NYMEX in the second quarter of 2022. A significant portion of our production receives prices reflecting market conditions south of New York at Transco Zone 6 Non-New York, which averaged $0.85/Mcf below NYMEX in the third quarter of 2022. We continue to expect our 2022 realized Marcellus differential to average $0.75/Mcf below NYMEX.

Operating expenses for the third quarter of 2022 increased to $103.8 million, or $10.47/BOE, compared to $83.4 million, or $9.74/BOE during the second quarter of 2022. On a per BOE basis, the amount increased due to higher planned well service activity during the period. We continue to expect our operating expense guidance for 2022 to be $10.00/BOE.

We reported net income of $305.9 million in the third quarter of 2022 compared to net income of $244.4 million in the second quarter of 2022. Higher net income in the third quarter of 2022 was due to a total commodity derivative instruments gain of $57.0 million, compared to a loss of $47.6 million in the second quarter of 2022. The higher commodity derivative instruments gain is due to lower forward market commodity prices at September 30, 2022, and the settlement of existing contracts during the quarter. Net income in the third quarter also benefited from higher production compared to the second quarter of 2022, partially offset by lower realized crude oil prices and higher associated operating costs.

In the third quarter of 2022 cash flow from operating activities increased to $409.9 million, compared to $250.9 million in the second quarter of 2022, primarily due to working capital adjustments and lower realized commodity derivative instrument losses. Third quarter adjusted funds flow increased to $355.6 million from $297.4 million over the same period. The increase was due to lower realized commodity derivative instruments losses and higher production, offset by lower realized crude oil prices.

At September 30, 2022, net debt was $391.1 million and our net debt to adjusted funds flow ratio decreased to 0.3x in the third quarter from 0.5x in the second quarter of 2022. Subsequent to the quarter, on November 3, 2022, Enerplus converted its $400 million revolving bank credit facility to a $365 million sustainability linked lending (“SLL”) bank credit facility, and extended the maturity to October 31, 2025. The $365 million SLL bank credit facility has similar targets to Enerplus’ $900 million SLL bank credit facility, which was renewed with $50 million maturing on October 31, 2025, and $850 million maturing on October 31, 2026. There were no other significant amendments or additions to the two agreements’ terms or covenants.

[1] This financial measure is a non-GAAP measure. See “Non-GAAP Measures” section in MD&A.

RESULTS OF OPERATIONS

Production

Daily production for the third quarter of 2022 averaged 107,808 BOE/day, an increase of 15% compared to average daily production of 94,142 BOE/day in the second quarter of 2022 with crude oil and natural gas liquids production increasing by 20% over the same period. The increase is primarily the result of 11.8 net wells coming on-stream in North Dakota.

For the three and nine months ended September 30, 2022, total production increased by 9% and 11%, respectively, when compared to the same periods in 2021. The increase in production for the three months ended September 30, 2022, compared to the same period in 2021, was due to higher capital activity in both North Dakota and the Marcellus during 2022. The increase in production for the nine months ended September 30, 2022, was due to additional on-stream activity, as well as a full period of production from the acquisition of Bruin E&P Holdco, LLC (the "Bruin Acquisition") and certain assets in the Williston Basin from Hess Bakken Investment II, LLC (the "Dunn County Acquisition"), which closed during the first half of 2021. The increases were partially offset by the sale of our interests in the Sleeping Giant field in Montana and the Russian Creek area in North Dakota in the Williston Basin, which closed during the fourth quarter of 2021.

Our crude oil and natural gas liquids weighting decreased to 63% from 64% for the three months ended September 30, 2022 and increased to 62% from 60% for the nine months ended September 30, 2022, compared to the same periods in 2021.

We have increased our annual average production guidance for 2022 to 99,750 BOE/day to 101,000 BOE/day, including 61,500 bbls/day to 62,500 bbls/day of crude oil and natural gas liquids, from 97,500 BOE/day to 101,500 BOE/day, including 59,500 bbls/day to 62,500 bbls/day of crude oil and natural gas liquids. For the fourth quarter of 2022, we expect average production of 105,000 BOE/day to 110,000 BOE/day, including 64,000 bbls/day to 68,000 bbls/day of crude oil and natural gas liquids. The updated production guidance includes the impact of the two previously announced Canadian asset divestments.

Average daily production volumes for the three and nine months ended September 30, 2022 and 2021 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2022**	**2021**	**% Change**	**2022**	**2021**	**% Change**
Light and medium oil (bbls/day)	2,038	2,188	(7%)	2,097	2,247	(7%)
Heavy oil (bbls/day)	2,651	3,356	(21%)	2,855	3,328	(14%)
Tight oil (bbls/day)	52,793	49,034	8%	46,194	40,613	14%
Total crude oil (bbls/day)	57,482	54,578	5%	51,146	46,188	11%
Natural gas liquids (bbls/day)	10,900	8,492	28%	9,319	7,246	29%
Conventional natural gas (Mcf/day)	6,909	7,703	(10%)	7,139	7,757	(8%)
Shale gas (Mcf/day)	229,649	209,550	10%	218,706	203,542	7%
Total natural gas (Mcf/day)	236,558	217,253	9%	225,845	211,299	7%
Total daily sales (BOE/day)	107,808	99,279	9%	98,106	88,651	11%

Pricing

The prices received for crude oil and natural gas production directly impact our earnings, cash flow from operating activities, adjusted funds flow and financial condition. The following table compares quarterly average benchmark prices, selling prices and differentials:

Pricing (average for the period)	**Nine months ended September 30, 2022**	**2021**	**Q3 2022**	**Q2 2022**	**Q1 2022**	**Q4 2021**	**Q3 2021**
Benchmarks							
WTI crude oil ($/bbl)	$ 98.09	$ 64.82	$ 91.56	$ 108.41	$ 94.29	$ 77.19	$ 70.56
Brent (ICE) crude oil ($/bbl)	102.33	67.78	97.81	111.78	97.38	79.80	73.23
Propane – Conway ($/bbl)	49.98	40.87	44.73	51.16	54.05	52.42	49.01
NYMEX natural gas – last day ($/Mcf)	6.77	3.18	8.20	7.17	4.95	5.83	4.01
CDN/US average exchange rate	0.78	0.80	0.77	0.78	0.79	0.79	0.79
CDN/US period end exchange rate	0.72	0.79	0.72	0.78	0.80	0.79	0.79
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 97.44	$ 62.12	$ 92.48	$ 108.77	$ 91.95	$ 75.21	$ 67.22
Natural gas liquids ($/bbl)	34.13	25.40	32.04	33.31	37.78	38.77	29.91
Natural gas ($/Mcf)	5.79	2.58	6.53	6.11	4.62	3.92	3.00
Average differentials							
Bakken DAPL – WTI ($/bbl)	$ 2.43	$ (1.24)	$ 3.60	$ 2.99	$ 0.71	$ 0.53	$ (0.68)
Brent (ICE) – WTI ($/bbl)	4.24	2.98	6.25	3.37	3.09	2.61	2.67
MSW Edmonton – WTI ($/bbl)	(1.82)	(4.14)	(2.01)	(0.50)	(2.96)	(3.10)	(4.07)
WCS Hardisty – WTI ($/bbl)	(15.74)	(12.51)	(19.89)	(12.80)	(14.53)	(14.64)	(13.58)
Transco Leidy monthly – NYMEX ($/Mcf)	(0.89)	(0.95)	(1.06)	(0.90)	(0.71)	(0.92)	(1.11)
Transco Z6 Non-New York monthly – NYMEX ($/Mcf)	(0.10)	(0.43)	(0.85)	(0.87)	1.42	(0.16)	(0.73)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI ($/bbl)	$ 1.07	$ (2.69)	$ 2.41	$ 0.85	$ (0.35)	$ (0.88)	$ (2.26)
Marcellus natural gas – NYMEX ($/Mcf)	(0.53)	(0.49)	(0.99)	(0.59)	0.01	(1.70)	(0.45)
Canada crude oil – WTI ($/bbl)	(14.75)	(12.55)	(15.96)	(12.17)	(16.31)	(13.82)	(12.87)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

During the third quarter of 2022, our realized crude oil sales price averaged $92.48/bbl, a decrease of 15% compared to the second quarter of 2022, and in line with the decrease in the underlying benchmark WTI price over the same period. Benchmark crude oil prices declined during the quarter largely due to macro-economic factors related to rising inflation and higher interest rates that have elevated risk of a global recession and a decrease in demand for crude oil. The decline in benchmark crude oil prices is also due to the continued release of crude oil Strategic Petroleum Reserve inventories into the U.S. Gulf Coast region. In response to the decline in global oil prices, the Organization of the Petroleum Exporting Countries Plus reduced production quotas in an effort to stabilize crude oil markets.

Bakken crude oil price differentials continued to strengthen during the quarter due to excess pipeline capacity in the region as regional production growth remains muted and strong physical prices for crude oil delivered to the U.S. Gulf Coast. Our realized Bakken crude oil price differential averaged $2.41/bbl above WTI during the third quarter of 2022, compared to $0.85/bbl above WTI during the second quarter of 2022. Given continued strength in Bakken crude oil price differentials and strong year-to-date realizations, we expect our 2022 realized Bakken crude oil price differential to average $1.25/bbl above WTI, compared to our previous guidance of $1.00/bbl above WTI.

Our realized sales price for natural gas liquids averaged $32.04/bbl during the third quarter of 2022 compared to $33.31/bbl during the second quarter of 2022. NGL benchmark prices declined during the quarter due to growing concerns around global recession risk, industrial demand for petrochemical feedstocks and inventory accumulations. Propane, which is the largest component of our NGL production, has experienced a significant decline in pricing as a percent of WTI throughout the year as seasonally low inventories have been restocked and concerns about foreign demand and export strength persist.

NATURAL GAS

Our realized natural gas sales price averaged $6.53/Mcf during the third quarter of 2022, an increase of 7% compared to the second quarter of 2022, while the NYMEX benchmark price increased by 14% over the same period. The difference in price realization versus the benchmark was due to seasonally weaker gas prices in the Marcellus, resulting in a wider differential for the third quarter of 2022.

Our realized Marcellus differential in the third quarter of 2022 averaged $0.99/Mcf below NYMEX compared to $0.59/Mcf below NYMEX in the second quarter of 2022. The decline in our realized differential was due to weaker regional prices in September as the market transitioned into the lower-demand shoulder season. We expect our Marcellus differential to remain supported through the rest of the year given the current local storage deficit and the increase in demand directly attributable to colder weather. Based on current year to date realizations and the outlook for the rest of 2022 we are maintaining our guidance of $0.75/Mcf below NYMEX.

FOREIGN EXCHANGE

Fluctuations in the Canadian and U.S. dollar exchange rate impacts our Canadian dollar denominated amounts such as Canadian netbacks, capital spending, general and administrative ("G&A") expenses, and dividends paid to Canadian residents. The U.S. dollar ended stronger in the third quarter of 2022 at $0.72 CDN/US, compared to $0.78 CDN/US at June 30, 2022 and $0.79 CDN/US at September 30, 2021. The average exchange rate of $0.78 CDN/US for the nine months ended September 30, 2022 was also stronger than the same period in 2021 when it averaged $0.80 CDN/US. U.S. dollar denominated working capital that is held in the Canadian parent entity will continue to result in unrealized foreign exchange gains and losses based on changes in the period end exchange rates.

Price Risk Management

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

We expect our commodity derivative contracts to continue to protect a portion of our cash flow from operating activities and adjusted funds flow. As of November 3, 2022, we have hedged 17,000 bbls/day for the remainder of 2022. Additionally, we have 15,000 bbls/day hedged for first half of 2023 and 5,000 bbls/day hedged for the second half of 2023. We have also hedged 120,000 Mcf/day for the period from November 1, 2022 to March 31, 2023 and 50,000 Mcf/day for the period from April 1, 2023 to October 31, 2023. Our crude oil contracts consist mainly of three-way collars, which limits upward price participation to the call strike level; additionally, the sold put 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 3, 2022:

	WTI Crude Oil ($/bbl)(1)(2)(3)			NYMEX Natural Gas ($/Mcf)(2)		
	Oct 1, 2022 – Dec 31, 2022	Jan 1, 2023 – Jun 30, 2023	Jul 1, 2023 – Dec 31, 2023	Oct 1, 2022 – Oct 31, 2022	Nov 1, 2022 – Mar 31, 2023	Apr 1, 2023 – Oct 31, 2023
Swaps						
Volume (Mcf/day)	–	–	–	40,000	–	–
Volume (bbls/day)	–	10,000	10,000	–	–	–
Swaps	–	–	–	$ 3.40	–	–
Brent - WTI Spread	–	$ 5.47	$ 5.47	–	–	–
3 Way Collars						
Volume (bbls/day)	17,000	15,000	5,000	–	–	–
Sold Puts	$ 40.00	$ 61.67	$ 65.00	–	–	–
Purchased Puts	$ 50.00	$ 79.33	$ 85.00	–	–	–
Sold Calls	$ 57.91	$ 114.31	$ 128.16	–	–	–
Collars						
Volume (Mcf/day)	–	–	–	60,000	120,000	50,000
Volume (bbls/day)	–	2,000	2,000	–	–	–
Purchased Puts	–	$ 5.00	$ 5.00	$ 3.77	$ 6.27	$ 4.05
Sold Calls	–	$ 75.00	$ 75.00	$ 4.50	$ 18.17	$ 7.00

(1) The total average deferred premium spent on our outstanding crude oil contracts is $1.50/bbl from October 1, 2022 – December 31, 2022 and $1.25/bbl from January 1, 2023 – December 31, 2023.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Upon closing of the Bruin Acquisition, Bruin E&P Holdco, LLC's outstanding crude oil contracts were recorded at a fair value liability of $76.4 million. At September 30, 2022, the remaining liability was $4.7 million on the Condensed Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired contracts are recognized in Condensed Consolidated Statement of Income/(Loss) and the Condensed Consolidated Balance Sheets to reflect changes in crude oil prices from the date of closing of the Bruin Acquisition.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	**Three months ended September 30,** 2022	2021	**Nine months ended September 30,** 2022	2021
Realized gains/(losses):				
Crude oil	$ (50.5)	$ (40.3)	$ (233.1)	$ (87.8)
Natural gas	(38.0)	(8.9)	(66.7)	(7.8)
Total realized gains/(losses)	$ (88.5)	$ (49.2)	$ (299.8)	$ (95.6)
Unrealized gains/(losses):				
Crude oil	$ 126.0	$ 3.3	$ 98.8	$ (158.3)
Natural gas	19.5	(11.5)	3.6	(21.6)
Total unrealized gains/(losses)	$ 145.5	$ (8.2)	$ 102.4	$ (179.9)
Total commodity derivative instruments gains/(losses)	$ 57.0	$ (57.4)	$ (197.4)	$ (275.5)

(Per BOE)	**Three months ended September 30,** 2022	2021	**Nine months ended September 30,** 2022	2021
Total realized gains/(losses)	$ (8.92)	$ (5.39)	$ (11.19)	$ (3.95)
Total unrealized gains/(losses)	14.67	(0.90)	3.82	(7.43)
Total commodity derivative instruments gains/(losses)	$ 5.75	$ (6.29)	$ (7.37)	$ (11.38)

During the three and nine months ended September 30, 2022, Enerplus realized losses of $50.5 million and $233.1 million, respectively, on our crude oil contracts, compared to realized losses of $40.3 million and $87.8 million for the same periods in 2021. For the three and nine months ended September 30, 2022, realized losses of $38.0 million and $66.7 million, respectively, were recorded on our natural gas contracts, compared to realized losses of $8.9 million and $7.8 million for the same periods in 2021. Cash losses recorded during the three and nine months ended September 30, 2022 were due to commodity prices exceeding the swap and sold call values on our commodity derivative contracts.

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, 2022, the fair value of our crude oil and natural gas contracts was in a net liability position of $23.0 million. For the three and nine months ended September 30, 2022, the change in the fair value of our crude oil contracts resulted in an unrealized gain of $126.0 million and an unrealized gain of $98.8 million, respectively, compared to unrealized gain of $3.3 million and an unrealized loss of $158.3 million, during the same periods in 2021. For the three and nine months ended September 30, 2022, we recorded unrealized gains on our natural gas contracts of $19.5 million and $3.6 million, respectively, compared to unrealized losses of $11.5 million and $21.6 million, during the same periods in 2021.

Crude Oil and Natural Gas Sales

($ millions, except per BOE amounts)	**Three months ended September 30,** 2022	2021	**Nine months ended September 30,** 2022	2021
Crude oil and natural gas sales	$ 663.5	$ 421.1	$ 1,804.7	$ 982.9
Per BOE	$ 66.90	$ 46.10	$ 67.38	$ 40.61

Crude oil and natural gas sales for the three and nine months ended September 30, 2022 were $663.5 million ($66.90/BOE) and $1,804.7 million ($67.38/BOE), respectively, compared to $421.1 million ($46.10/BOE) and $982.9 million ($40.61/BOE) for the same periods in 2021. The increase in revenue was primarily due to additional production from our capital program and the Bruin and the Dunn County acquisitions completed during the first half of 2021 as well as higher commodity prices.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Operating expenses	$ 103.8	$ 89.1	$ 270.5	$ 212.4
Per BOE	$ 10.47	$ 9.76	$ 10.10	$ 8.78

For three and nine months ended September 30, 2022, operating expenses were $103.8 million, or $10.47/BOE, and $270.5 million, or $10.10/BOE, respectively, compared to $89.1 million, or $9.76/BOE, and $212.4 million, or $8.78/BOE, for the same periods in 2021. The increases were primarily due to the impact of contracts with price escalators linked to WTI crude oil prices and the Consumer Price Index, higher planned well service activity, and higher U.S. crude oil weighting in our production mix partially as a result of the Bruin and Dunn County acquisitions.

We continue to expect our operating expenses guidance for 2022 to be $10.00/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Transportation costs	$ 41.3	$ 32.5	$ 114.9	$ 87.9
Per BOE	$ 4.16	$ 3.56	$ 4.29	$ 3.63

For three and nine months ended September 30, 2022, transportation costs were $41.3 million, or $4.16/BOE, and $114.9 million, or $4.29/BOE, respectively, compared to $32.5 million, or $3.56/BOE, and $87.9 million, or $3.63/BOE, for the same periods in 2021. The increase compared to the same periods in 2021 is primarily the result of increased U.S. production with higher associated transportation costs and additional firm transportation commitments on the Dakota Access Pipeline (“DAPL”) as a result of the Bruin Acquisition and participation in the DAPL expansion in August 2021.

We continue to expect our transportation costs guidance for 2022 to be $4.25/BOE.

Production Taxes

($ millions, except per BOE amounts)	Three months ended September 30, 2022	2021	Nine months ended September 30, 2022	2021
Production taxes	$ 48.2	$ 30.4	$ 127.4	$ 69.1
Per BOE	$ 4.86	$ 3.33	$ 4.76	$ 2.86
Production taxes (% of crude oil and natural gas sales)	7.3%	7.2%	7.1%	7.0%

Production taxes for three and nine months ended September 30, 2022 were $48.2 million, or 7.3%, and $127.4 million, or 7.1%, respectively, compared to $30.4 million, or 7.2%, and $69.1 million, or 7.0%, for the same periods in 2021. The increase in total production taxes was due to higher realized prices, as well as higher crude oil production which attracts a higher rate of production tax, compared to the same periods in 2021.

We continue to expect production taxes to average 7% in 2022.

Netbacks

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

	Three months ended September 30, 2022		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	79,304 BOE/day	171,027 Mcfe/day	107,808 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 75.60	$ 7.12	$ 66.90
Operating expenses	(13.87)	(0.17)	(10.47)
Transportation costs	(3.72)	(0.90)	(4.16)
Production taxes	(6.46)	(0.07)	(4.86)
Netback before impact of commodity derivative contracts	$ 51.55	$ 5.98	$ 47.41
Realized hedging gains/(losses)	(6.93)	(2.41)	(8.92)
Netback after impact of commodity derivative contracts	$ 44.62	$ 3.57	$ 38.49
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 376.1	$ 94.1	$ 470.2
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 325.6	$ 56.2	$ 381.7

(1) This financial measure is a non-GAAP financial measure. See "Non-GAAP Measures" section in this MD&A.

	Three months ended September 30, 2021		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	72,425 BOE/day	161,122 Mcfe/day	99,279 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 55.21	$ 3.60	$ 46.10
Operating expenses	(12.89)	(0.22)	(9.76)
Transportation costs	(2.84)	(0.92)	(3.56)
Production taxes	(4.45)	(0.05)	(3.33)
Netback before impact of commodity derivative contracts	$ 35.03	$ 2.41	$ 29.45
Realized hedging gains/(losses)	(6.05)	(0.60)	(5.39)
Netback after impact of commodity derivative contracts	$ 28.98	$ 1.81	$ 24.06
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 233.4	$ 35.7	$ 269.1
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 193.1	$ 26.8	$ 219.9

(1) This financial measure is a non-GAAP financial measure. See "Non-GAAP Measures" section in this MD&A.

Netbacks by Property Type	Nine months ended September 30, 2022 Crude Oil	Natural Gas	Total
Average Daily Production	69,526 BOE/day	171,481 Mcfe/day	98,106 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 79.73	$ 6.23	$ 67.38
Operating expenses	(13.73)	(0.21)	(10.10)
Transportation costs	(3.84)	(0.90)	(4.29)
Production taxes	(6.57)	(0.06)	(4.76)
Netback before impact of commodity derivative contracts	$ 55.59	$ 5.06	$ 48.23
Realized hedging gains/(losses)	(12.28)	(1.42)	(11.19)
Netback after impact of commodity derivative contracts	$ 43.31	$ 3.64	$ 37.04
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 1,055.1	$ 236.9	$ 1,291.9
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 822.0	$ 170.3	$ 992.1

(1) This financial measure is a non-GAAP financial measure. See "Non-GAAP Measures" section in this MD&A.

Netbacks by Property Type	Nine months ended September 30, 2021 Crude Oil	Natural Gas	Total
Average Daily Production	61,177 BOE/day	164,835 Mcfe/day	88,651 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 51.41	$ 2.77	$ 40.61
Operating expenses	(12.18)	(0.20)	(8.78)
Transportation costs	(2.82)	(0.91)	(3.63)
Production taxes	(4.04)	(0.04)	(2.86)
Netback before impact of commodity derivative contracts	$ 32.37	$ 1.62	$ 25.34
Realized hedging gains/(losses)	(5.26)	(0.17)	(3.95)
Netback after impact of commodity derivative contracts	$ 27.11	$ 1.45	$ 21.39
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 540.6	$ 72.9	$ 613.5
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 452.8	$ 65.1	$ 517.9

(1) This financial measure is a non-GAAP financial measure. See "Non-GAAP Measures" section in this MD&A.

Total netbacks before and after hedging for the three and nine months ended September 30, 2022 were higher compared to the same periods in 2021, primarily due to higher production and higher realized prices.

For the three and nine months ended September 30, 2022, crude oil properties accounted for 80% and 82%, respectively, of total netback before hedging, compared to 87% and 88% during the same periods in 2021.

G&A Expenses

Total G&A expenses include G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans").

($ millions)	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
Cash:				
G&A expenses	$ 10.9	$ 8.6	$ 31.5	$ 27.8
Share-based compensation expense	1.2	0.8	3.6	4.9
Non-Cash:				
Share-based compensation expense	3.8	3.4	14.3	4.3
Equity swap gain	—	(0.3)	(1.0)	(1.3)
G&A recovery	(0.1)	(0.1)	(0.3)	(0.3)
Total G&A expenses	$ 15.8	$ 12.4	$ 48.1	$ 35.4

(Per BOE)	Three months ended September 30, 2022	Three months ended September 30, 2021	Nine months ended September 30, 2022	Nine months ended September 30, 2021
Cash:				
G&A expenses	$ 1.10	$ 0.94	$ 1.18	$ 1.15
Share-based compensation expense	0.12	0.09	0.13	0.20
Non-Cash:				
Share-based compensation expense	0.38	0.37	0.53	0.18
Equity swap gain	—	(0.03)	(0.04)	(0.05)
G&A recovery	(0.01)	(0.01)	(0.01)	(0.01)
Total G&A expenses	$ 1.59	$ 1.36	$ 1.79	$ 1.47

Cash G&A expenses for three and nine months ended September 30, 2022 were $10.9 million, or $1.10/BOE, and $31.5 million, or $1.18/BOE, respectively, compared to $8.6 million, or $0.94/BOE, and $27.8 million, or $1.15/BOE, for the same periods in 2021. For the three and nine months ended September 30, 2022, total cash G&A expenses increased due to inflationary pressure on labour and services.

SBC can be equity-settled or cash-settled, depending on the underlying plan to which it relates. SBC that is cash-settled for the three and nine months ended September 30, 2022, was $1.2 million, or $0.12/BOE, and $3.6 million, or $0.13/BOE, respectively, compared to $0.8 million, or $0.09/BOE, and $4.9 million, or $0.20/BOE, for the same periods in 2021. For the three months ended September 30, 2022, the higher expense was due to a larger share price increase in 2022 compared to the same period in 2021. For the nine months ended September 30, 2022, the lower expense was due to fewer Director Deferred Share Units outstanding and a smaller share price increase in 2022 compared to the same period in 2021. Equity-settled non-cash SBC for the three and nine months ended September 30, 2022 was $3.8 million, or $0.38/BOE, and $14.3 million, or $0.53/BOE, respectively, compared to $3.4 million, or $0.37/BOE, and $4.3 million, or $0.18/BOE, for the same periods in 2021. Performance Share Units ("PSUs"), as one of the equity-settled LTI plans, are impacted by performance multipliers. For the three and nine months ended September 30, 2022, the multipliers were higher, resulting in an increase in expense compared to the same periods in 2021.

Enerplus had hedged a portion of the outstanding cash-settled units under our LTI plans. During the three and nine months ended September 30, 2022, we recorded a market-to-market gain of nil and $1.0 million, respectively (2021 – gains of $0.3 million and $1.3 million, respectively), as a result of the higher share price. Enerplus settled its equity derivative contracts during the second quarter of 2022 and did not have any equity derivatives outstanding at September 30, 2022.

We continue to expect our cash G&A expenses guidance for 2022 to be $1.20/BOE.

Interest Expense

For the three and nine months ended September 30, 2022, we recorded a total interest expense of $6.5 million and $18.6 million, respectively, compared to $8.2 million and $21.6 million for the same periods in 2021. The decrease was primarily due to lower debt levels during the three and nine months ended September 30, 2022, as cash flow was used to repay debt incurred in 2021 to fund the Bruin and Dunn County acquisitions. During the nine months ended September 30, 2022, we made a principal payment on our 2014 senior notes, and our third principal payment and final bullet payment outstanding on our 2012 senior notes.

At September 30, 2022, approximately 47% of Enerplus' debt was based on fixed interest rates and 53% on floating interest rates, with weighted average interest rates of 4.2% and 2.5%, respectively.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Realized:				
Foreign exchange (gain)/loss	$ 0.1	$ 0.5	$ —	$ 2.9
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	(1.0)	(0.3)	(1.1)	(1.9)
Unrealized:				
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	17.0	(14.2)	14.9	(7.2)
Total foreign exchange (gain)/loss	$ 16.1	$ (14.0)	$ 13.8	$ (6.2)
CDN/US average exchange rate	0.77	0.79	0.78	0.80
CDN/US period end exchange rate	0.72	0.79	0.72	0.79

For three and nine months ended September 30, 2022, Enerplus recorded foreign exchange losses of $16.1 million and $13.8 million, respectively, compared to gains of $14.0 million and $6.2 million for the same periods in 2021. Realized foreign exchange gains and losses relate primarily to day-to-day transactions recorded in foreign currencies, as well as 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.

At September 30, 2022, $203.2 million of outstanding senior notes and $230.0 million drawn on the SLL bank credit facility and revolving bank credit facility (together referred to as the "Bank Credit Facilities") were designated as net investment hedges against the investment in our U.S. subsidiary. As a result, unrealized foreign exchange gains and losses on the translation of U.S. dollar denominated debt are included in Other Comprehensive Income/(Loss). For the three and nine months ended September 30, 2022, Other Comprehensive Income/(Loss) included unrealized losses of $24.3 million and $33.0 million, respectively, on our U.S. dollar denominated senior notes and Bank Credit Facilities compared to an unrealized loss of $13.7 million and an unrealized gain of $2.2 million, for the same periods in 2021.

Property, Plant and Equipment ("PP&E")

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Capital spending(1)	$ 114.5	$ 63.6	$ 346.4	$ 221.3
Office capital	0.2	0.3	0.6	2.0
Sub-total	114.7	63.9	347.0	223.3
Bruin Acquisition	$ —	$ —	$ —	$ 520.2
Dunn County Acquisition	—	—	—	305.1
Property and land acquisitions	16.3	3.1	19.7	7.1
Property divestments(1)	(4.2)	0.2	(19.4)	(3.8)
Sub-total	12.1	3.3	0.3	828.6
Total	$ 126.8	$ 67.2	$ 347.3	$ 1,051.9

(1) Excludes changes in non-cash investing working capital.

Capital spending for the three and nine months ended September 30, 2022 totaled $114.5 million and $346.4 million, respectively, compared to $63.6 million and $221.3 million for the same periods in 2021. The increase is mainly due to increased capital activity on our North Dakota properties. Capital spending during the third quarter of 2022 included $94.2 million on our U.S. crude oil properties and $15.7 million on our Marcellus natural gas properties.

During the first nine months of 2021, we completed the Bruin Acquisition for total cash consideration of $465.0 million, or $420.2 million after purchase price adjustments, with $520.2 million allocated to PP&E, excluding the assumed asset retirement obligation. We also completed the Dunn County Acquisition for total cash consideration of $306.8 million, with $305.1 million allocated to PP&E, excluding the assumed asset retirement obligation.

Property divestments for the three and nine months ended September 30, 2022 were $4.2 million and $19.4 million, respectively, compared to nil and $3.8 million, respectively, for the same periods in 2021. Property divestments for the nine months ended September 30, 2022 relate to the sale of minor non-operated interests in North Dakota and Pennsylvania.

On July 28, 2022, the Company announced it had entered into a definitive agreement to sell certain Canadian assets located in Alberta for total consideration of CDN$140 million, prior to closing adjustments. The total consideration comprises cash, common shares of purchaser, and an amortizing interest-bearing loan provided by Enerplus. Production from the assets is approximately 3,400 BOE/day (60% crude oil). The sale closed on October 31, 2022.

Subsequent to the quarter, on November 2, 2022, the Company announced it had entered into a definitive agreement to sell substantially all of its remaining Canadian assets located in Alberta and Saskatchewan for total consideration of CDN$245 million, prior to closing adjustments. The total consideration comprises cash of CDN$210 million and CDN$35 million in common shares of the purchaser. Production from the assets is approximately 3,000 BOE/day (99% crude oil). The sale is expected to close in December 2022.

We are revising our annual capital spending guidance for 2022 to be $430 million from a range between $400 million to $440 million.

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2022	2021	2022	2021
DD&A expense	$ 82.2	$ 81.3	$ 219.0	$ 194.4
Per BOE	$ 8.29	$ 8.90	$ 8.18	$ 8.03

DD&A related to PP&E is recognized using the unit of production method based on proved reserves. Enerplus recorded DD&A expense of $82.2 million, or $8.29/BOE, for the three months ended September 30, 2022 compared to $81.3 million, or $8.90/BOE, in the same period in 2021. The decrease in per BOE for the three months ended September 30, 2022 is primarily a result of reserve additions and revisions at December 31, 2021. For the nine months ended September 30, 2022, DD&A expense was $219.0 million, or $8.18/BOE, and $194.4 million, or $8.03/BOE, for the same period in 2021. The increase in total DD&A expense and per BOE is a result of additional production volumes and higher PP&E costs from the Bruin and the Dunn County acquisitions, partially offset by reserve additions and revisions at December 31, 2021.

Impairment

PP&E

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country cost centre basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves ("Standardized Measure"), using constant prices as defined by the U.S. Securities and Exchange Commission (the "SEC") guidelines. 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.

Trailing twelve-month average crude oil and natural gas prices improved throughout 2021 and 2022. There were no impairments for the three and nine months ended September 30, 2022. For the three and nine months ended September 30, 2021, we recorded a PP&E impairment of nil and $3.4 million, respectively, related to our Canadian assets.

Many factors influence the allowed ceiling value compared to 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 2022, 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. See "Risk Factors and Risk Management – Risk of Impairment of Oil and Gas Properties and Deferred Tax Assets" in the Annual MD&A.

Asset Retirement Obligation ("ARO")

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets, such as surface leases, wells, facilities and pipelines. Total ARO included on the Condensed Consolidated Balance Sheet is based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate, the timing of the costs to be incurred in future periods and estimates for inflation. We have estimated the net present value of our asset retirement obligation to be $155.2 million at September 30, 2022, compared to $132.8 million at December 31, 2021.

For the three and nine months ended September 30, 2022, ARO settlements were $1.6 million and $12.7 million, respectively, compared to $1.7 million and $8.5 million, respectively, during the same periods in 2021.

Enerplus benefited from provincial government assistance to support the clean-up of inactive or abandoned crude oil and natural gas wells. These programs provide direct funding to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. The funding received by the contractor is reflected as a reduction to ARO. For the three and nine months ended September 30, 2022, Enerplus benefitted from $0.3 million and $0.8 million, respectively, in government assistance compared to $0.2 million and $2.1 million, respectively, for the same periods in 2021.

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, including lease payments relating 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, 2022, our total lease liability was $23.0 million (December 31, 2021 - $28.9 million). In addition, ROU assets of $20.5 million were recorded, which relate to our lease liabilities less lease incentives (December 31, 2021 - $26.1 million).

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Current tax expense/(recovery)	$ 7.9	$ (0.9)	$ 24.9	$ 2.5
Deferred tax expense/(recovery)	93.1	31.4	174.6	31.1
Total tax expense/(recovery)	$ 101.0	$ 30.5	$ 199.5	$ 33.6

For the three and nine months ended September 30, 2022, we recorded a current tax expense of $7.9 million and $24.9 million, respectively, compared to a recovery of $0.9 million and an expense of $2.5 million for the same periods in 2021. The increase in current tax in 2022 is due to additional U.S. Federal and state tax resulting from higher net income for the year and the utilization of the majority of our net operating loss carryforward. Many factors influence taxable income including future commodity prices, production levels, development activities, capital spending, and overall profitability. We continue to expect 2022 cash tax of 2.0% – 3.0% of adjusted funds flow before tax assuming WTI of $85.00/bbl and NYMEX of $6.00/Mcf.

For the three and nine months ended September 30, 2022, we recorded a deferred income tax expense of $93.1 million and $174.6 million, respectively, compared to an expense of $31.4 million and $31.1 million for the same periods in 2021. The higher deferred tax expense in 2022 is due to higher income.

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 forecast average prices and costs. There is risk of a valuation allowance in future periods if commodity prices weaken or other evidence indicates that some of our deferred income tax assets will not be realized. See "Risk Factors and Risk Management – Risk of Impairment of Oil and Gas Properties and Deferred Tax Assets" in the Annual MD&A. For the nine months ended September 30, 2022, no valuation allowance was recorded against our Canadian income related deferred tax asset, however, a full valuation allowance has been recorded against our deferred income tax assets related to capital items. Our deferred income tax asset recorded in Canada is $197.4 million offset by a deferred income tax liability in the U.S. of $11.1 million as at September 30, 2022 (December 31, 2021 - $380.9 million net asset).

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, commodity derivative contracts, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, 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 nine months, after which it drops to 3.0x. At September 30, 2022, our senior debt to adjusted EBITDA ratio was 0.4x and our net debt to adjusted funds flow ratio was 0.3x. Although a capital management measure that 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.

Net debt at September 30, 2022 decreased to $391.1 million, compared to $640.4 million at December 31, 2021. Total debt was comprised of our senior notes and Bank Credit Facilities, totaling $433.2 million, less cash on hand of $42.2 million.
At September 30, 2022, through our Bank Credit Facilities, we had total credit capacity of $1.3 billion, of which $230.0 million was drawn. We expect to finance our working capital requirements through cash, adjusted funds flow and our credit capacity. We have sufficient liquidity to meet our financial commitments for the near term.

Subsequent to the quarter, on November 3, 2022, Enerplus converted its $400 million revolving bank credit facility to a $365 million SLL bank credit facility, and extended the maturity to October 31, 2025. The $365 million SLL bank credit facility has similar targets to Enerplus' $900 million SLL bank credit facility, which was renewed with $50 million maturing on October 31, 2025, and $850 million maturing on October 31, 2026. There were no other significant amendments or additions to the two agreements' terms or covenants.

Our reinvestment rate[1] was 32% and 38% for the three and nine months ended September 30, 2022, respectively, compared to 31% and 49%, respectively, for the same periods in 2021.

During the three and nine months ended September 30, 2022, a total of $123.3 million and $271.3 million, respectively, was returned to shareholders through share repurchases and dividends, compared to $18.1 million and $32.8 million for the same periods in 2021. During the third quarter of 2022, we announced our intention to increase our expected 2022 return of capital to at least 60% of free cash flow[1] commencing in the second half of 2022 and continuing through 2023, an increase from 50% of free cash flow in the first half of 2022. We also previously announced an increase to the expected minimum return of capital level to $425 million for 2022. Subsequent to the quarter, the Board of Directors approved a 10% increase to the quarterly dividend to $0.055 per share, from $0.050 per share, beginning December 2022. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

During the three months ended September 30, 2022, a total of 7,913,168 common shares were repurchased and cancelled under the Normal Course Issuer Bid ("NCIB") at an average price of $14.13 per share, for total consideration of $111.8 million. During the nine months ended September 30, 2022, a total of 18,126,090 common shares were repurchased and cancelled under the NCIB at an average price of $13.35 per share, for total consideration of $241.9 million. During the three and nine months ended September 30, 2021, 1,657,650 common shares were repurchased and cancelled under the NCIB at an average price of $6.12 per share, for total consideration of $10.1 million.

At September 30, 2022, we were in compliance with all covenants under the Bank Credit Facilities 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. Agreements relating to our Bank Credit Facilities and the senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

[1] This financial measure is a non-GAAP financial measure. See "Non-GAAP Measures" section in MD&A.

The following table lists our financial covenants at September 30, 2022:

Covenant Description		September 30, 2022
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	0.4x
Total debt to adjusted EBITDA	4.0x	0.4x
Total debt to capitalization	55%	21%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA(1)	3.0x - 3.5x	0.4x
Senior debt to consolidated present value of total proved reserves(2)	60%	11%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	50.0x

Definitions
"Senior debt" is calculated as the sum of drawn amounts on our bank credit facilities, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion, 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, 2022 was $370.6 million and $1,218.5 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 $823.7 million adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) 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.
(2) 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)	2022	2021	2022	2021
Dividends(1)	$ 11.5	$ 7.9	$ 29.4	$ 22.7
Per weighted average share (Basic)	$ 0.050	$ 0.030	$ 0.126	$ 0.089

(1) Excludes changes in non-cash financing working capital.

During the three and nine months ended September 30, 2022, we declared total dividends of $11.5 million, or $0.050 per share, and $29.4 million, or $0.126 per share, respectively, compared to $7.9 million, or $0.030 per share, and $22.7 million, or $0.089 per share, for the same periods in 2021. The total amount of dividends paid to shareholders has increased compared to the same period in 2021 due to the increased sustainability of the business and our intention to increase return of capital to shareholders.

Subsequent to the quarter, the Board of Directors approved a 10% increase to the quarterly dividend to $0.055 per share, from $0.050 per share, beginning December 2022. We expect to fund the dividend through the free cash flow generated by the business.

Shareholders' Capital

	Nine months ended September 30,	
	2022	2021
Share capital ($ millions)	$ 2,926.2	$ 3,206.2
Common shares outstanding (thousands)	226,966	255,092
Weighted average shares outstanding – basic (thousands)	237,835	252,432
Weighted average shares outstanding – diluted (thousands)	245,403	256,900

For the nine months ended September 30, 2022, a total of 2,192,538 units vested pursuant to our treasury-settled LTI plans, including the impact of performance multipliers (2021 – 2,014,193). In total, 1,240,000 shares were issued from treasury and $8.0 million was transferred from paid-in capital to share capital (2021 – 1,140,000; $9.4 million). We elected to cash-settle the remaining units related to the required tax withholdings for the total amount of $11.6 million (2021 – $3.6 million).

During the third quarter, Enerplus received approval from the Toronto Stock Exchange ("TSX") to renew its NCIB to purchase up to 10% of the public float (within the meaning of the TSX rules) during a 12-month period. Enerplus completed its previous NCIB in July 2022.

During the nine months ended September 30, 2022, 18,126,090 common shares were repurchased and cancelled under the NCIB at an average price of $13.35 per share, for total consideration of $241.9 million. Of the amount paid, $175.8 million was charged to share capital and $66.1 million was credited to accumulated deficit. At September 30, 2022, 17,682,231 common shares were available for repurchase under the current NCIB.

During the nine months ended September 30, 2021, 1,657,650 common shares were repurchased and cancelled under the NCIB at an average price of $6.12 per share, for total consideration of $10.1 million. Of the amount paid, $16.5 million was charged to share capital and $6.4 million was credited to accumulated deficit.

Subsequent to September 30, 2022 and up to November 2, 2022, we repurchased 2,729,590 common shares under the NCIB at an average price of $16.00 per common share, for total consideration of $43.7 million.

At November 2, 2022, we had 224,236,699 common shares outstanding. In addition, an aggregate of 10,297,759 common shares may be issued to settle outstanding grants under the PSUs and Restricted Share Unit plans assuming the maximum performance multiplier of 2.0 times for the PSUs.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended September 30, 2022			Three months ended September 30, 2021		
($ millions, except per unit amounts)	U.S.	Canada	Total	U.S.	Canada	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	52,793	4,689	57,482	49,035	5,543	54,578
Natural gas liquids (bbls/day)	10,612	288	10,900	8,209	283	8,492
Natural gas (Mcf/day)	229,466	7,092	236,558	209,454	7,799	217,253
Total average daily production (BOE/day)	101,649	6,159	107,808	92,153	7,126	99,279
Pricing(1)						
Crude oil ($/bbl)	$ 93.96	$ 75.76	$ 92.48	$ 68.31	$ 57.66	$ 67.22
Natural gas liquids ($/bbl)	31.53	50.85	32.04	29.50	41.84	29.91
Natural gas ($/Mcf)	6.61	3.97	6.53	2.97	3.86	3.00
Property, Plant and Equipment						
Capital and office expenditures	$ 113.6	$ 1.1	$ 114.7	$ 61.0	$ 2.9	$ 63.9
Acquisitions, including property and land	16.0	0.3	16.3	2.7	0.4	3.1
Property divestments	(4.3)	0.1	(4.2)	—	0.2	0.2
Netback Before Impact of Commodity Derivative Contracts(2)						
Crude oil and natural gas sales	$ 626.7	$ 36.8	$ 663.5	$ 387.6	$ 33.5	$ 421.1
Operating expenses	(91.4)	(12.4)	(103.8)	(79.0)	(10.1)	(89.1)
Transportation cost	(40.1)	(1.2)	(41.3)	(31.0)	(1.5)	(32.5)
Production taxes	(47.4)	(0.8)	(48.2)	(29.9)	(0.5)	(30.4)
Netback before impact of commodity derivative contracts	$ 447.8	$ 22.4	$ 470.2	$ 247.7	$ 21.4	$ 269.1
Other Expenses						
Commodity derivative instruments (gain)/loss	$ —	$ (57.0)	$ (57.0)	$ —	$ 57.4	$ 57.4
General and administrative expense(3)	1.3	14.5	15.8	6.5	5.9	12.4
Current income tax expense/(recovery)	7.9	—	7.9	(0.9)	—	(0.9)

(1) Before transportation costs and the effects of commodity derivative instruments.
(2) This financial measure is a non-GAAP financial measure. See "Non-GAAP Measures" section in this MD&A.
(3) Includes share-based compensation.

($ millions, except per unit amounts)	Nine months ended September 30, 2022 U.S.	Canada	Total	Nine months ended September 30, 2021 U.S.	Canada	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	46,193	4,953	51,146	40,614	5,574	46,188
Natural gas liquids (bbls/day)	9,021	298	9,319	6,916	330	7,246
Natural gas (Mcf/day)	218,505	7,340	225,845	203,296	8,003	211,299
Total average daily production (BOE/day)	91,632	6,474	98,106	81,413	7,238	88,651
Pricing(1)						
Crude oil ($/bbl)	$ 98.95	$ 83.34	$ 97.44	$ 63.48	$ 52.26	$ 62.12
Natural gas liquids ($/bbl)	33.45	54.78	34.13	24.98	34.25	25.40
Natural gas ($/Mcf)	5.82	4.92	5.79	2.54	3.52	2.58
Property, Plant and Equipment						
Capital and office expenditures	$ 341.8	$ 5.2	$ 347.0	$ 213.0	$ 10.3	$ 223.3
Acquisitions, including property and land	18.6	1.1	19.7	830.7	1.7	832.4
Property divestments	(19.5)	0.1	(19.4)	—	(3.8)	(3.8)
Netback Before Impact of Commodity Derivative Contracts(2)						
Crude oil and natural gas sales	$ 1,677.2	$ 127.5	$ 1,804.7	$ 892.1	$ 90.8	$ 982.9
Operating expenses	(235.5)	(35.0)	(270.5)	(181.5)	(30.9)	(212.4)
Transportation cost	(111.3)	(3.6)	(114.9)	(83.1)	(4.8)	(87.9)
Production taxes	(125.2)	(2.2)	(127.4)	(67.6)	(1.5)	(69.1)
Netback before impact of commodity derivative contracts	$ 1,205.2	$ 86.7	$ 1,291.9	$ 559.9	$ 53.6	$ 613.5
Other Expenses						
Commodity derivative instruments (gain)/loss	$ —	$ 197.4	$ 197.4	$ —	$ 275.5	$ 275.5
General and administrative expense(3)	19.0	29.1	48.1	23.9	11.5	35.4
Current income tax expense/(recovery)	24.9	—	24.9	2.5	—	2.5

(1) Before transportation costs and the effects of commodity derivative instruments.
(2) This financial measure is a non-GAAP financial measure. See "Non-GAAP Measures" section in this MD&A.
(3) Includes share-based compensation.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Crude Oil and Natural Gas Sales	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2022				
Third Quarter	$ 663.5	$ 305.9	$ 1.32	$ 1.28
Second Quarter	628.0	244.4	1.01	0.99
First Quarter	513.2	33.2	0.14	0.13
Total 2022	$ 1,804.7	$ 583.6	$ 2.47	$ 2.40
2021				
Fourth Quarter	$ 499.7	$ 176.9	$ 0.71	$ 0.68
Third Quarter	421.1	98.1	0.38	0.38
Second Quarter	333.4	(50.9)	(0.20)	(0.20)
First Quarter	228.4	10.3	0.04	0.04
Total 2021	$ 1,482.6	$ 234.4	$ 0.93	$ 0.90
2020				
Fourth Quarter	$ 150.2	$ (161.6)	$ (0.73)	$ (0.73)
Third Quarter	144.2	(84.4)	(0.38)	(0.38)
Second Quarter	88.9	(444.6)	(2.00)	(2.00)
First Quarter	170.4	(2.8)	(0.01)	(0.01)
Total 2020	$ 553.7	$ (693.4)	$ (3.12)	$ (3.12)

Crude oil and natural gas sales increased to $663.5 million during the third quarter of 2022, compared to $628.0 million during the second quarter of 2022. The increase in crude oil and natural gas sales was a result of higher production during the third quarter of 2022 compared to the second quarter of 2022. We reported net income of $305.9 million during the third quarter of 2022 compared to net income of $244.4 million during the second quarter of 2022. The increase was primarily due to a gain recorded on commodity derivative instruments of $57.0 million during the third quarter of 2022, compared to a $47.6 million loss recorded in the second quarter of 2022.

Crude oil and natural gas sales increased in 2021 compared to 2020 due to higher production from the Bruin and the Dunn County acquisitions and higher realized prices. We reported a net loss in 2020 due to PP&E impairments totaling $751.7 million and a goodwill impairment of $149.2 million on our U.S. reporting unit recorded in the twelve months ended December 31, 2020.

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, 2021.

2022 GUIDANCE

The following table summarizes our updated 2022 guidance and includes the impact of the two previously announced Canadian asset divestments.

Summary of 2022 Annual Expectations	Target Annual Results
Capital spending ($ millions)	$430 (from $400 - $440)
Average annual production (BOE/day)	99,750 - 101,000 (from 97,500 - 101,500)
Average annual crude oil and natural gas liquids production (bbls/day)	61,500 - 62,500 (from 59,500 - 62,500)
Fourth quarter average production (BOE/day)	105,000 - 110,000
Fourth quarter average crude oil and natural gas liquids production (bbls/day)	64,000 - 68,000
Average production tax rate (% of gross sales, before transportation)	7%
Operating expenses (per BOE)	$10.00
Transportation costs (per BOE)	$4.25
Cash G&A expenses (per BOE)	$1.20
Current tax expense	2% - 3% of adjusted funds flow before tax

Differential/Basis Outlook(1)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	$1.25/bbl (from $1.00/bbl)
Average Marcellus natural gas differential (compared to NYMEX natural gas)	$(0.75)/Mcf

(1) Excludes transportation costs.

NON-GAAP MEASURES

This MD&A includes references to certain non-GAAP financial measures and non-GAAP ratios used by the Company to evaluate its financial performance, financial position or cash flow. Non-GAAP financial measures are financial measures disclosed by a company that (a) depict historical or expected future financial performance, financial position or cash flow of a company, (b) with respect to their composition, exclude amounts that are included in, or include amounts that are excluded from, the composition of the most directly comparable financial measure disclosed in the primary financial statements of the company, (c) are not disclosed in the financial statements of the company and (d) are not a ratio, fraction, percentage or similar representation. Non-GAAP ratios are financial measures disclosed by a company that are in the form of a ratio, fraction, percentage or similar representation that has a non-GAAP financial measure as one or more of its components, and that are not disclosed in the financial statements of the company.

These non-GAAP financial measures and non-GAAP ratios do not have standardized meanings or definitions as prescribed by U.S. GAAP and may not be comparable with the calculation of similar financial measures by other entities. For each measure, we have indicated the composition of the measure, identified the GAAP equivalency to the extent one exists, provided comparative detail where appropriate, indicated the reconciliation of the measure to the mostly directly comparable GAAP financial measure and provided details on the usefulness of the measure for the reader. These non-GAAP financial measures and non-GAAP ratios should not be considered as a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP.

"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 adjusting for certain unrealized items and other items that the company considers appropriate to adjust given their irregular nature. The most directly comparable GAAP measure is net income/(loss). No income tax rate adjustments or valuation allowances on deferred taxes were recorded for the three and nine months ended September 30, 2022 and 2021. The calculation follows:

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Net income/(loss)	**$ 305.9**	**$ 98.1**	**$ 583.6**	**$ 57.5**
Unrealized derivative instrument (gain)/loss	(145.5)	8.0	(103.4)	178.6
Asset impairment	—	—	—	3.4
Other expense related to investing activities	—	—	13.1	—
Unrealized foreign exchange (gain)/loss	17.0	(14.2)	14.9	(7.2)
Tax effect on above items	30.5	0.2	17.8	(41.7)
Other income related to investing activities	—	(4.6)	—	(4.6)
Adjusted net income/(loss)	**$ 207.9**	**$ 87.5**	**$ 526.0**	**$ 186.0**

"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. The most directly comparable GAAP measure is cash flow from operating activities.

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Cash flow from/(used in) operating activities	$ 409.9	$ 182.2	$ 856.8	$ 321.3
Asset retirement obligation settlements	1.6	1.7	12.7	8.5
Changes in non-cash operating working capital	(55.9)	19.3	45.4	124.2
Adjusted funds flow	**$ 355.6**	**$ 203.2**	**$ 914.9**	**$ 454.0**
Capital spending	(114.5)	(63.6)	(346.4)	(221.3)
Free cash flow	**$ 241.1**	**$ 139.6**	**$ 568.5**	**$ 232.7**

“Netback before impact of commodity derivative contracts” and **“Netback after impact of commodity derivative contracts”** is used by Enerplus and is useful to investors and securities analysts, in evaluating operating performance of our crude oil and natural gas assets, both before and after consideration of our realized gain/(loss) on commodity derivative instruments. A direct GAAP equivalent does not exist for these measures, although a reconciliation is provided below:

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2022	2021	2022	2021
Crude oil and natural gas sales	$ 663.5	$ 421.1	$ 1,804.7	$ 982.9
Less:				
Operating expenses	(103.8)	(89.1)	(270.5)	(212.4)
Transportation expenses	(41.3)	(32.5)	(114.9)	(87.9)
Production taxes	(48.2)	(30.4)	(127.4)	(69.1)
Netback before impact of commodity derivative contracts	**$ 470.2**	**$ 269.1**	**$ 1,291.9**	**$ 613.5**
Net realized gain/(loss) on derivative instruments	(88.5)	(49.2)	(299.8)	(95.6)
Netback after impact of commodity derivative contracts	**$ 381.7**	**$ 219.9**	**$ 992.1**	**$ 517.9**

Other Financial Measures

CAPITAL MANAGEMENT MEASURES

Capital management measures are financial measures disclosed by a company that (a) are intended to enable an individual to evaluate a company’s objectives, policies and processes for managing the company's capital, (b) are not a component of a line item disclosed in the primary financial statements of the company, (c) are disclosed in the notes to the financial statements of the company, and (d) are not disclosed in the primary financial statements of the company. The following section provides an explanation of the composition of those capital management measures if not previously provided:

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

“Net Debt” is calculated as current and long-term debt associated with senior notes plus any outstanding Bank Credit Facilities balances, less cash and cash equivalents. “Net debt” is useful to investors and securities analysts in analyzing financial liquidity and Enerplus considers net debt to be a key measure of capital management.

“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 net debt divided by a trailing twelve months of adjusted funds flow. There is no directly comparable GAAP equivalent for this measure, and it is not equivalent to any of our debt covenants.

SUPPLEMENTARY FINANCIAL MEASURES

Supplementary financial measures are financial measures disclosed by a company that (a) are, or are intended to be, disclosed on a periodic basis to depict the historical or expected future financial performance, financial position or cash flow of a company, (b) are not disclosed in the financial statements of the company, (c) are not non-GAAP financial measures, and (d) are not non-GAAP ratios. The following section provides an explanation of the composition of those supplementary financial measures if not previously provided:

“Capital spending” Capital and office expenditures, excluding other capital assets/office capital and property and land acquisitions and divestments.

“Cash general and administrative expenses” or **“Cash G&A expenses”** General and administrative expenses that are settled through cash payout, as opposed to expenses that relate to accretion or other non-cash allocations that are recorded as part of general and administrative expenses.

“Cash share-based compensation” or **“Cash SBC expenses”** Share-based compensation that is settled by way of cash payout, as opposed to equity settled.

“Reinvestment rate” Comparing the amount of our capital spending to adjusted funds flow (as a percentage).

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, at September 30, 2022, 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, 2022 and ended September 30, 2022 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 Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and 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: Enerplus' return of capital plans, including expectations regarding payment of dividends and the source of funds related thereto; expectations regarding Enerplus' share repurchase program, including timing and amounts thereof and the funding of the share repurchase program from free cash flow; the sale of Enerplus' assets in Canada and the completion, timing, and anticipated benefits and proceeds thereof; expected impact of the sale of Enerplus' assets in Canada on its operations and financial results, including updated 2022 and future capital spending guidance and expected capital spending levels in 2023 and the future, and the impact thereof on our production levels and land holdings; expected production volumes in 2022, including the production mix, and updated 2022 production guidance; 2022 capital spending guidance and expected capital spending levels in 2022; expectations regarding free cash flow generation and long-term capital spending reinvestment rates; expected operating strategy in 2022; the proportion of our anticipated crude oil and natural gas liquids production that is hedged and the expected effectiveness of such hedges in protecting our cash flow from operating activities and adjusted funds flow; oil and natural gas prices and differentials and expectations regarding the market environment and our commodity risk management program in 2022; updated and existing 2022 Bakken and Marcellus differential guidance; expectations regarding realized oil and natural gas prices; expected operating, transportation and cash G&A expenses and production taxes and updated 2022 guidance with respect thereto; 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; deferred income taxes and the time at which cash taxes may be paid; expected 2022 cash tax as a percentage of adjusted funds flow before tax; future debt and working capital levels, financial capacity, liquidity and capital resources to fund capital spending, working capital requirements and deficits and senior note repayments; expectations regarding our ability to comply with or renegotiate debt covenants under the Bank Credit Facilities and outstanding senior notes; and our future acquisitions and dispositions.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: the ability to fund our return of capital plans, including both dividends at the current level and the share repurchase program, from free cash flow as expected; that our common share trading price will be at levels, and that there will be no other alternatives, that, in each case, make share repurchases an appropriate and best strategic use of our free cash flows; the timing and proceeds from the sale of Enerplus' remaining assets in Canada, as well as benefits of the sale of Enerplus' assets in Canada and its ability to realize such benefits; that we will conduct our operations and achieve results of operations as anticipated; the continued operation of DAPL; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current and anticipated commodity prices, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions, the impact of inflation, weather conditions, storage fundamentals and expectations regarding the duration and overall impact of COVID-19; 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 closing of the sale of Enerplus' remaining assets in Canada in a timely manner and pursuant to the terms thereof; our ability to comply with our debt covenants; our ability to meet the targets associated with the SLL bank credit facility; the availability of third party services; expected transportation costs; the extent of our liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; factors used to assess the realizability of our deferred income tax assets; and the availability of technology and process to achieve environmental targets.

In addition, our 2022 guidance described in this MD&A is based on: a WTI price of $85.00/bbl, a NYMEX price of $6.00/Mcf, a Bakken crude oil price differential of $1.25/bbl above WTI, a Marcellus natural gas price differential of $0.75/Mcf below NYMEX and a CDN/USD exchange rate of $0.72. 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 increased 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: failure by Enerplus to achieve the expected timing, or realize anticipated proceeds or benefits, of the sale of Enerplus' assets in Canada; continued instability, or further deterioration, in global economic and market environment, including from COVID-19 or similar events, inflation and/or the Ukraine/Russia conflict and heightened geopolitical risks; decreases in commodity prices or volatility in commodity prices; changes in realized prices of Enerplus' products from those currently anticipated; changes in the demand for or supply of our products, including global energy demand; volatility in our common share trading price and free cash flow that could impact our planned share repurchases and dividend levels; unanticipated operating results, results from our capital spending activities or production declines; legal proceedings or other events inhibiting or preventing operation of 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; risks associated with the realization of our deferred income tax assets; 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 Facilities and/or 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; changes in law or government programs or policies in Canada or the United States; 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 at December 31, 2021), which are available at www.sedar.com, www.sec.gov *and through Enerplus' website at* www.enerplus.com.

The forward-looking information contained in this MD&A speaks 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. Any forward-looking information contained herein are expressly qualified by this cautionary statement.