Exhibit 99.1

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

The following discussion and analysis of financial results is dated August 4, 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 six months ended June 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. 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 second quarter of 2022 averaged 94,142 BOE/day, an increase of 2% compared to average production of 92,196 BOE/day in the first quarter of 2022. The increase is primarily the result of increased completions activity in North Dakota and the Marcellus during the second quarter of 2022, partially offset by the impact of severe winter weather in North Dakota in April. As a result of strong production volumes during the first half of the year, and despite the expected loss of production associated with the recently announced sale of assets in Canada, we are increasing our average annual production guidance for 2022 to 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, from 96,000 BOE/day to 101,000 BOE/day, including 58,500 bbls/day to 62,500 bbls/day of crude oil and natural gas liquids.

On July 28, 2022, the Company announced it had entered into a definitive agreement to sell Canadian assets located in Alberta for total consideration of CDN$140 million ($109 million), subject to customary purchase price 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).

Capital spending during the second quarter of 2022 was $132.9 million, compared to $99.0 million during the first quarter of 2022, with the majority of the spending focused on our U.S. crude oil properties. We continue to expect capital spending for 2022 to range between $400 to $440 million.

Bakken crude oil price differentials turned positive to WTI due to continued increasing demand, excess pipeline capacity in the region, and strong price differentials for physical crude oil delivered to the U.S. Gulf Coast. Our realized Bakken crude oil price differential averaged $0.85/bbl above WTI during the second quarter of 2022, compared to $0.35/bbl below WTI during the first quarter of 2022. Given stronger year-to-date realizations, we expect our 2022 realized Bakken crude oil price differential to average $1.00/bbl above WTI, compared to our previous guidance of a price differential at par with WTI pricing.

Our realized Marcellus sales price differential widened compared to the previous quarter, as expected, due to seasonal demand in the region. Our differential in the second quarter of 2022 averaged $0.59/Mcf below NYMEX, compared to $0.01/Mcf above NYMEX in the first 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 $0.87/Mcf below NYMEX in the second quarter of 2022. We continue to expect Marcellus differentials to widen for the remainder of 2022, due to the seasonal impact on natural gas prices in the region and are therefore maintaining our guidance of $0.75/Mcf below NYMEX.

Operating expenses for the second quarter of 2022 were $83.4 million, or $9.74/BOE, consistent with $83.2 million, or $10.03/BOE during the first quarter of 2022. On a per BOE basis, the amount decreased due to increased production during the second quarter of 2022 compared to the first quarter of 2022. We are revising our operating expenses guidance for 2022 to $10.00/BOE from $9.75 - $10.50/BOE.

We reported net income of $244.4 million in the second quarter of 2022 compared to net income of $33.2 million in the first quarter of 2022. Lower net income in the prior quarter was due to a higher total commodity derivative instruments loss of $206.8 million, compared to a loss of $47.6 million in the second quarter of 2022. The lower commodity derivative instruments loss is due to stabilizing commodity prices and the settlement of existing contracts. Net income in the second quarter also benefited from higher realized prices and production compared to the first quarter of 2022, partially offset by a $71.7 million deferred income tax expense compared to a $9.8 million expense in the first quarter of 2022.

In the second quarter of 2022 cash flow from operating activities and adjusted funds flow increased to $250.9 million and $297.4 million, respectively, from $196.0 million and $261.9 million in the first quarter of 2022, due to higher realized prices and increased production offset by higher realized commodity derivative instruments losses.

At June 30, 2022, net debt was $546.0 million and our net debt to adjusted funds flow ratio decreased to 0.5x in the second quarter from 0.7x in the first quarter of 2022.

During the second quarter of 2022, a total of $102.8 million was returned to shareholders through share repurchases and dividends compared to $45.1 million in the first quarter of 2022. The Company completed its Normal Course Issuer Bid ("NCIB") in July 2022 and fully repurchased 10% of its public float (within the meaning under Toronto Stock Exchange ("TSX") rules).

Subsequent to June 30, 2022, the Board of Directors approved an increase to our 2022 return of capital plan to at least 60% of free cash flow[1], commencing in the second half of 2022 and continuing through 2023. We are also increasing the minimum 2022 return of capital commitment to $425 million, from $350 million previously. In connection with this plan, the Board of Directors has approved the renewal of Enerplus' NCIB to purchase another 10% of the public float during the following 12-month period and a 16% increase to the quarterly dividend to $0.05 per share, from $0.043 per share, beginning September 2022. We expect to fund the dividend and share repurchases through the free cash flow[1] generated by the business.

RESULTS OF OPERATIONS

Production

Daily production for the second quarter of 2022 averaged 94,142 BOE/day, an increase of 2% compared to average daily production of 92,196 BOE/day in the first quarter of 2022. The increase is primarily the result of increased completions activity in North Dakota and the Marcellus with 22.8 net wells coming on-stream in the second quarter of 2022, partially offset by the impact of severe winter weather in North Dakota in April.

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

The increase in production for the three and six months ended June 30, 2022 compared to the same periods in 2021 was partially due to 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. This increased production was 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 (the “Sleeping Giant/Russian Creek Divestment”), which closed during the fourth quarter of 2021.

For the three and six months ended June 30, 2022, total production increased by 2% and 12%, respectively, when compared to the same periods in 2021. The increase in the second quarter of 2022 compared to the same in period 2021 was due to the aforementioned acquisition and divestment activity and an increase in production in the Marcellus.

Our crude oil and natural gas liquids weighting decreased to 60% from 62% for the three months ended June 30, 2022 and increased to 61% from 58% for the six months ended June 30, 2022, compared to the same periods in 2021.

As a result of strong production volumes during the first half of the year, and despite the expected loss of production associated with the recently announced sale of assets in Canada with current production of approximately 3,400 BOE/day (60% crude oil), we are increasing our average annual production guidance for 2022 to 97,500 BOE/day to 101,500 BOE/day, including 59,500 bbls/day to 62,500 bbls/day in crude oil and natural gas liquids, from 96,000 BOE/day to 101,000 BOE/day, including 58,500 bbls/day to 62,500 bbls/day in crude oil and natural gas liquids.

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

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2022**	**2021**	**% Change**	**2022**	**2021**	**% Change**
Light and medium oil (bbls/day)	2,082	2,213	(6%)	2,127	2,277	(7%)
Heavy oil (bbls/day)	2,886	3,243	(11%)	2,959	3,313	(11%)
Tight oil (bbls/day)	43,245	44,193	(2%)	42,839	36,333	18%
Total crude oil (bbls/day)	48,213	49,649	(3%)	47,925	41,923	14%
Natural gas liquids (bbls/day)	8,653	7,941	9%	8,516	6,613	29%
Conventional natural gas (Mcf/day)	7,319	6,846	7%	7,256	7,784	(7%)
Shale gas (Mcf/day)	216,334	203,726	6%	213,144	200,489	6%
Total natural gas (Mcf/day)	223,653	210,572	6%	220,400	208,273	6%
Total daily sales (BOE/day)	94,142	92,685	2%	93,174	83,248	12%

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)	Six months ended June 30, 2022	Six months ended June 30, 2021	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021
Benchmarks							
WTI crude oil ($/bbl)	$ 101.35	$ 61.96	$ 108.41	$ 94.29	$ 77.19	$ 70.56	$ 66.07
Brent (ICE) crude oil ($/bbl)	104.58	65.06	111.78	97.38	79.80	73.23	69.02
NYMEX natural gas – last day ($/Mcf)	6.06	2.76	7.17	4.95	5.83	4.01	2.83
CDN/US average exchange rate	0.79	0.80	0.78	0.79	0.79	0.79	0.81
CDN/US period end exchange rate	0.78	0.81	0.78	0.80	0.79	0.79	0.81
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 100.46	$ 58.75	$ 108.77	$ 91.95	$ 75.21	$ 67.22	$ 62.50
Natural gas liquids ($/bbl)	35.49	22.46	33.31	37.78	38.77	29.91	18.47
Natural gas ($/Mcf)	5.38	2.35	6.11	4.62	3.92	3.00	1.96
Average differentials							
Bakken DAPL – WTI ($/bbl)	$ 1.85	$ (1.51)	$ 2.99	$ 0.71	$ 0.53	$ (0.68)	$ (0.40)
Brent (ICE) – WTI ($/bbl)	3.23	3.10	3.37	3.09	2.61	2.67	2.95
MSW Edmonton – WTI ($/bbl)	(1.73)	(4.18)	(0.50)	(2.96)	(3.10)	(4.07)	(3.11)
WCS Hardisty – WTI ($/bbl)	(13.67)	(11.98)	(12.80)	(14.53)	(14.64)	(13.58)	(11.49)
Transco Leidy monthly – NYMEX ($/Mcf)	(0.80)	(0.87)	(0.90)	(0.71)	(0.92)	(1.11)	(1.17)
Transco Z6 Non-New York monthly – NYMEX ($/Mcf)	0.28	(0.27)	(0.87)	1.42	(0.16)	(0.73)	(0.72)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI ($/bbl)	$ 0.23	$ (2.97)	$ 0.85	$ (0.35)	$ (0.88)	$ (2.26)	$ (2.81)
Marcellus natural gas – NYMEX ($/Mcf)	(0.30)	(0.51)	(0.59)	0.01	(1.70)	(0.45)	(0.89)
Canada crude oil – WTI ($/bbl)	(14.18)	(12.31)	(12.17)	(16.31)	(13.82)	(12.87)	(11.65)

(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 second quarter of 2022, our realized crude oil sales price averaged $108.77/bbl, an increase of 18% compared to the first quarter of 2022, due to increases in both the underlying benchmark WTI price as well as strong price differentials for Bakken crude oil. Crude oil prices remained strong with the continuation of the Ukraine/Russia conflict, and the imposition of economic sanctions on Russia. Additionally, concerns remain over the Organization of the Petroleum Exporting Countries Plus ("OPEC+") nations' ability to materially increase production. Crude oil demand continues to recover globally as the world emerges from the coronavirus pandemic ("COVID-19"), however inflation, rising interest rates and the risk of a recession has lowered demand growth expectations.

Bakken crude oil price differentials continued to strengthen during the quarter 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 $0.85/bbl above WTI during the second quarter of 2022, compared to $0.35/bbl below WTI during the first quarter of 2022. Given stronger year-to-date realizations and continued strong Gulf Coast pricing, we now expect our 2022 realized Bakken crude oil price differential to be $1.00/bbl above WTI compared to our previous guidance that was at par with WTI pricing.

Our realized sales price for natural gas liquids averaged $33.31/bbl during the second quarter of 2022, a decrease of 12% compared to the first quarter of 2022. The decrease is due to lower seasonal benchmark prices.

NATURAL GAS

Our realized natural gas sales price averaged $6.11/Mcf during the second quarter of 2022, an increase of 32% compared to the first quarter of 2022, while the NYMEX benchmark price increased by 45% over the same period. The difference in price realization versus the benchmark was due to the seasonal nature of basis pricing in the Marcellus.

Our realized Marcellus sales price differential widened compared to the previous quarter, as expected, due to lower shoulder season demand in the region. Our differential in the quarter averaged $0.59/Mcf below NYMEX compared to $0.01/Mcf above NYMEX in the first 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 $0.87/Mcf below NYMEX in the second quarter of 2022. We continue to expect Marcellus differentials to widen for the remainder of 2022, due to the seasonal nature of natural gas prices in the region and 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 slightly stronger in the second quarter of 2022 at $0.78 CDN/US, compared to $0.80 CDN/US at March 31, 2022 and $0.81 CDN/US at June 30, 2021. The average exchange rate of $0.79 CDN/US for the six months ended June 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. See Note 13 to the Financial Statements for further detail.

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 instruments contracts to continue to protect a portion of our cash flow from operating activities and adjusted funds flow. As of August 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 100,000 Mcf/day for the period from July 1, 2022 to October 31, 2022 and 50,000 Mcf/day for the period from November 1, 2022 to March 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 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 August 3, 2022:

	WTI Crude Oil ($/bbl)[(1)(2)(3)]			NYMEX Natural Gas ($/Mcf)[(2)]	
	Jul 1, 2022 – Dec 31, 2022	**Jan 1, 2023 – Jun 30, 2023**	**Jul 1, 2023 – Dec 31, 2023**	**Jul 1, 2022 – Oct 31, 2022**	**Nov 1, 2022 – Mar 31, 2023**
Swaps					
Volume (Mcf/day)	–	–	–	40,000	–
Swaps	–	–	–	$ 3.40	–
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	50,000
Volume (bbls/day)	–	2,000	2,000	–	–
Purchased Puts	–	$ 5.00	$ 5.00	$ 3.77	$ 6.50
Sold Calls	–	$ 75.00	$ 75.00	$ 4.50	$ 16.41

(1) The total average deferred premium spent on our outstanding crude oil contracts is $1.50/bbl from July 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's outstanding crude oil contracts were recorded at a fair value liability of $76.4 million. At June 30, 2022, the remaining liability was $10.3 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 June 30, 2022**	**2021**	**Six months ended June 30, 2022**	**2021**
Realized gains/(losses):				
Crude oil	$ (109.9)	$ (31.5)	$ (182.6)	$ (47.5)
Natural gas	(28.3)	0.5	(28.7)	1.1
Total realized gains/(losses)	$ (138.2)	$ (31.0)	$ (211.3)	$ (46.4)
Unrealized gains/(losses):				
Crude oil	$ 68.5	$ (119.6)	$ (27.2)	$ (161.5)
Natural gas	22.1	(11.2)	(15.9)	(10.2)
Total unrealized gains/(losses)	$ 90.6	$ (130.8)	$ (43.1)	$ (171.7)
Total commodity derivative instruments gains/(losses)	$ (47.6)	$ (161.8)	$ (254.4)	$ (218.1)

(Per BOE)	**Three months ended June 30, 2022**	**2021**	**Six months ended June 30, 2022**	**2021**
Total realized gains/(losses)	$ (16.13)	$ (3.68)	$ (12.53)	$ (3.08)
Total unrealized gains/(losses)	10.58	(15.52)	(2.56)	(11.40)
Total commodity derivative instruments gains/(losses)	$ (5.55)	$ (19.20)	$ (15.09)	$ (14.48)

During the three and six months ended June 30, 2022, Enerplus realized losses of $109.9 million and $182.6 million, respectively, on our crude oil contracts, compared to realized losses of $31.5 million and $47.5 million for the same periods in 2021. For the three and six months ended June 30, 2022, realized losses of $28.3 million and $28.7 million, respectively, were recorded on our natural gas contracts, compared to realized gains of $0.5 million and $1.1 million for the same periods in 2021. Cash losses recorded during the three and six months ended June 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 June 30, 2022, the fair value of our crude oil and natural gas contracts was in a net liability position of $174.1 million. For the three and six months ended June 30, 2022, the change in the fair value of our crude oil contracts resulted in an unrealized gain of $68.5 million and an unrealized loss of $27.2 million, respectively, compared to unrealized losses of $119.6 million and $161.5 million, during the same periods in 2021. For the three and six months ended June 30, 2022, we recorded an unrealized gain on our natural gas contracts of $22.1 million and an unrealized loss of $15.9 million, respectively, compared to unrealized losses of $11.2 million and $10.2 million, during the same periods in 2021.

Crude Oil and Natural Gas Sales

($ millions, except per BOE amounts)	**Three months ended June 30, 2022**	**2021**	**Six months ended June 30, 2022**	**2021**
Crude oil and natural gas sales	$ 628.0	$ 333.4	$ 1,141.2	$ 561.8
Per BOE	$ 73.31	$ 39.53	$ 67.67	$ 37.28

Crude oil and natural gas sales for the three and six months ended June 30, 2022 were $628.0 million, or $73.31/BOE, and $1,141.2 million, or $67.67/BOE, respectively, compared to $333.4 million, or $39.53/BOE, and $561.8 million, or $37.28/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. See Note 11 to the Interim Financial Statements for further details.

Operating Expenses

($ millions, except per BOE amounts)	**Three months ended June 30, 2022**	**2021**	**Six months ended June 30, 2022**	**2021**
Operating expenses	$ 83.4	$ 72.1	$ 166.6	$ 123.3
Per BOE	$ 9.74	$ 8.55	$ 9.88	$ 8.18

For the three and six months ended June 30, 2022, operating expenses were $83.4 million, or $9.74/BOE, and $166.6 million, or $9.88/BOE, respectively, compared to $72.1 million, or $8.55/BOE, and $123.3 million, or $8.18/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, as well as a higher U.S. crude oil weighting in our production mix as a result of the Bruin and Dunn County acquisitions.

We are revising our operating expenses guidance for 2022 to $10.00/BOE from $9.75 - $10.50/BOE.

Transportation Costs

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2022	2021	2022	2021
Transportation costs	$ 37.8	$ 29.5	$ 73.6	$ 55.4
Per BOE	$ 4.41	$ 3.50	$ 4.36	$ 3.68

For the three and six months ended June 30, 2022, transportation costs were $37.8 million, or $4.41/BOE, and $73.6 million, or $4.36/BOE, respectively, compared to $29.5 million, or $3.50/BOE, and $55.4 million, or $3.68/BOE, for the same periods in 2021. The increases compared to the same periods in 2021 are primarily a 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 are revising our transportation costs guidance for 2022 to $4.25/BOE from $4.15/BOE.

Production Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2022	2021	2022	2021
Production taxes	$ 43.8	$ 24.9	$ 79.2	$ 38.7
Per BOE	$ 5.11	$ 2.95	$ 4.70	$ 2.57
Production taxes (% of crude oil and natural gas sales)	7.0%	7.5%	6.9%	6.9%

Production taxes for the three and six months ended June 30, 2022 were $43.8 million, or 7.0%, and $79.2 million, or 6.9%, respectively, compared to $24.9 million, or 7.5%, and $38.7 million, or 6.9%, for the same periods in 2021. The increase in total production taxes was due to higher realized prices, 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 June 30, 2022		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	65,070 BOE/day	174,433 Mcfe/day	94,142 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 88.37	$ 6.60	$ 73.31
Operating expenses	(13.51)	(0.22)	(9.74)
Transportation costs	(3.97)	(0.90)	(4.41)
Production taxes	(7.25)	(0.06)	(5.11)
Netback before impact of commodity derivative contracts	$ 63.64	$ 5.42	$ 54.05
Realized hedging gains/(losses)	(18.56)	(1.78)	(16.13)
Netback after impact of commodity derivative contracts	$ 45.08	$ 3.64	$ 37.92
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 376.9	$ 86.1	$ 463.0
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 267.0	$ 57.8	$ 324.8

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

Netbacks by Property Type	Three months ended June 30, 2021 Crude Oil	Natural Gas	Total
Average Daily Production	65,947 BOE/day	160,436 Mcfe/day	92,685 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 50.56	$ 2.06	$ 39.53
Operating expenses	(11.51)	(0.21)	(8.55)
Transportation costs	(2.67)	(0.92)	(3.50)
Production taxes	(4.06)	(0.04)	(2.95)
Netback before impact of commodity derivative contracts	$ 32.32	$ 0.89	$ 24.53
Realized hedging gains/(losses)	(5.25)	0.04	(3.68)
Netback after impact of commodity derivative contracts	$ 27.07	$ 0.93	$ 20.85
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 194.0	$ 12.9	$ 206.9
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 162.4	$ 13.5	$ 175.9

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

Netbacks by Property Type	Six months ended June 30, 2022 Crude Oil	Natural Gas	Total
Average Daily Production	64,556 BOE/day	171,711 Mcfe/day	93,174 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 82.29	$ 5.78	$ 67.67
Operating expenses	(13.64)	(0.23)	(9.88)
Transportation costs	(3.92)	(0.90)	(4.36)
Production taxes	(6.64)	(0.05)	(4.70)
Netback before impact of commodity derivative contracts	$ 58.09	$ 4.60	$ 48.73
Realized hedging gains/(losses)	(15.62)	(0.92)	(12.53)
Netback after impact of commodity derivative contracts	$ 42.47	$ 3.68	$ 36.20
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 679.0	$ 142.8	$ 821.8
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 496.4	$ 114.1	$ 610.5

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

Netbacks by Property Type	Six months ended June 30, 2021 Crude Oil	Natural Gas	Total
Average Daily Production	55,461 BOE/day	166,723 Mcfe/day	83,248 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 48.89	$ 2.35	$ 37.28
Operating expenses	(11.71)	(0.19)	(8.18)
Transportation costs	(2.81)	(0.90)	(3.68)
Production taxes	(3.77)	(0.03)	(2.57)
Netback before impact of commodity derivative contracts	$ 30.60	$ 1.23	$ 22.85
Realized hedging gains/(losses)	(4.73)	0.04	(3.08)
Netback after impact of commodity derivative contracts	$ 25.87	$ 1.27	$ 19.77
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 307.2	$ 37.2	$ 344.4
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 259.7	$ 38.3	$ 298.0

(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 six months ended June 30, 2022 were higher compared to the same periods in 2021, primarily due to higher production and higher realized prices.

For the three and six months ended June 30, 2022, crude oil properties accounted for 81% and 83%, respectively, of total netback before hedging, compared to 94% and 89% 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"). See Note 12 and Note 15 to the Interim Financial Statements for further details.

($ millions)	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Cash:				
G&A expenses	$ 9.4	$ 8.8	$ 20.6	$ 19.2
Share-based compensation expense	0.3	1.9	2.4	4.1
Non-Cash:				
Share-based compensation expense	5.7	0.1	10.5	0.9
Equity swap gain	(0.6)	(0.6)	(1.0)	(1.0)
G&A recovery	(0.1)	(0.1)	(0.2)	(0.2)
Total G&A expenses	$ 14.7	$ 10.1	$ 32.3	$ 23.0

(Per BOE)	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Cash:				
G&A expenses	$ 1.10	$ 1.04	$ 1.22	$ 1.28
Share-based compensation expense	0.04	0.23	0.14	0.27
Non-Cash:				
Share-based compensation expense	0.67	0.01	0.62	0.06
Equity swap gain	(0.07)	(0.07)	(0.06)	(0.07)
G&A recovery	(0.01)	(0.01)	(0.01)	(0.01)
Total G&A expenses	$ 1.73	$ 1.20	$ 1.92	$ 1.53

Cash G&A expenses for the three and six months ended June 30, 2022 were $9.4 million, or $1.10/BOE, and $20.6 million, or $1.22/BOE, respectively, compared to $8.8 million, or $1.04/BOE, and $19.2 million, or $1.28/BOE, for the same periods in 2021. For the three months ended June 30, 2022, total cash G&A expenses increased modestly on a total dollar basis and per BOE basis compared to the same period in 2021. For the six months ended June 30, 2022, total cash G&A expenses increased on a total dollar basis, however, were lower on a per BOE basis compared to the same period in 2021, due to higher production.

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 six months ended June 30, 2022, was $0.3 million, or $0.04/BOE, and $2.4 million, or $0.14/BOE, respectively, compared to $1.9 million, or $0.23/BOE, and $4.1 million, or $0.27/BOE, for the same periods in 2021. The lower expense was due to fewer Director Deferred Share Units outstanding at June 30, 2022 and a smaller share price increase in 2022 compared to the same period in 2021. Equity-settled non-cash SBC for the three and six months ended June 30, 2022 was $5.7 million, or $0.67/BOE, and $10.5 million, or $0.62/BOE, respectively, compared to $0.1 million, or $0.01/BOE, and $0.9 million, or $0.06/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 six months ended June 30, 2022, the multipliers were higher, resulting in an increase in expense compared to the same period in 2021.

Enerplus had hedged a portion of the outstanding cash-settled units under our LTI plans. During the three and six months ended June 30, 2022, we recorded a market-to-market gain of $0.6 million and $1.0 million, respectively (2021 – gains of $0.6 million and $1.0 million, respectively), as a result of the higher share price. Enerplus settled its equity derivative contracts during the second quarter of 2022 and does not have any equity derivatives outstanding at June 30, 2022.

We are revising our cash G&A expenses guidance for 2022 to $1.20/BOE from $1.25/BOE.

Interest Expense

For the three and six months ended June 30, 2022, we recorded a total interest expense of $6.1 million and $12.2 million, respectively, compared to $7.8 million and $13.4 million for the same periods in 2021. The decrease was primarily due to lower debt levels during the second quarter of 2022, compared to the higher debt levels incurred in the first six months of 2021 to fund the Bruin and Dunn County acquisitions. During the three months ended June 30, 2022, we made our third principal payment and final bullet payment outstanding on our 2012 senior notes, which carry higher interest rates than our Sustainability-Linked Lending Bank Credit Facility and revolving bank credit facility (together referred to as the "Bank Credit Facilities").

At June 30, 2022, approximately 39% of Enerplus' debt was based on fixed interest rates and 61% on floating interest rates, with weighted average interest rates of 4.2% and 2.2%, respectively. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2022	2021	2022	2021
Realized:				
Foreign exchange (gain)/loss	$ 0.2	$ 2.9	$ (0.1)	$ 2.4
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	(0.1)	(2.0)	(0.1)	(1.6)
Unrealized:				
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	(3.3)	6.9	(2.1)	7.0
Total foreign exchange (gain)/loss	$ (3.2)	$ 7.8	$ (2.3)	$ 7.8
CDN/US average exchange rate	0.78	0.81	0.79	0.80
CDN/US period end exchange rate	0.78	0.81	0.78	0.81

For the three and six months ended June 30, 2022, Enerplus recorded foreign exchange gains of $3.2 million and $2.3 million, respectively, compared to losses of $7.8 million and $7.8 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 June 30, 2022, $224.2 million of outstanding senior notes and $347.2 million drawn on 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 six months ended June 30, 2022, Other Comprehensive Income/(Loss) included unrealized losses of $14.1 million and $8.7 million, respectively, on our U.S. dollar denominated senior notes and Bank Credit Facilities compared to unrealized gains of $10.2 million and $15.9 million, for the same periods in 2021.

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

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2022	2021	2022	2021
Capital spending(1)	$ 132.9	$ 105.9	$ 231.9	$ 157.7
Office capital	0.1	0.4	0.4	1.7
Sub-total	133.0	106.3	232.3	159.4
Bruin Acquisition	$ —	$ 25.5	$ —	$ 520.2
Dunn County Acquisition	—	305.1	—	305.1
Property and land acquisitions	1.5	1.6	3.4	4.0
Property divestments(1)	(8.6)	—	(15.2)	(4.0)
Sub-total	(7.1)	332.2	(11.8)	825.3
Total	$ 125.9	$ 438.5	$ 220.5	$ 984.7

(1) Excludes changes in non-cash investing working capital. See Note 17 to the Interim Financial Statements for further details.

Capital spending for the three and six months ended June 30, 2022 totaled $132.9 million and $231.9 million, respectively, compared to $105.9 million and $157.7 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 second quarter of 2022 included $119.1 million on our U.S. crude oil properties and $11.6 million on our Marcellus natural gas assets.

During the first six 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 six months ended June 30, 2022 were $8.6 million and $15.2 million, respectively, compared to nil and $4.0 million, respectively, for the same periods in 2021. Property divestments for the six months ended June 30, 2022 relate to the sale of minor non-operated interests in North Dakota and Colorado.

Subsequent to June 30, 2022, Enerplus announced it had entered into a definitive agreement to sell Canadian assets located in Alberta for total consideration of CDN$140 million ($109 million), subject to customary purchase price adjustments.

We continue to expect capital spending for 2022 to range between $400 – $440 million.

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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2022	2021	2022	2021
DD&A expense	$ 70.1	$ 76.4	$ 136.8	$ 113.1
Per BOE	$ 8.18	$ 9.06	$ 8.11	$ 7.51

DD&A related to PP&E is recognized using the unit of production method based on proved reserves. Enerplus recorded DD&A expense of $70.1 million for the three months ended June 30, 2022 compared to $76.4 million in same period in 2021. The decrease in total DD&A expense and per BOE is primarily a result of reserves additions and revisions at December 31, 2021. For the six months ended June 30, 2022, DD&A expense was $136.8 million, or $8.11/BOE, and $113.1 million, or $7.51/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 into the second quarter of 2022. There were no impairments for the three and six months ended June 30, 2022. For the three and six months ended June 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 $163.0 million at June 30, 2022, compared to $132.8 million at December 31, 2021.

For the three and six months ended June 30, 2022, ARO settlements were $2.3 million and $11.1 million, respectively, compared to $1.2 million and $6.8 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 six months ended June 30, 2022, Enerplus benefitted from $0.1 million and $0.5 million, respectively, in government assistance compared to $0.6 million and $1.9 million, respectively, for the same periods in 2021. 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, 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 June 30, 2022, our total lease liability was $25.3 million (December 31, 2021 - $28.9 million). In addition, ROU assets of $22.8 million were recorded, which relate to our lease liabilities less lease incentives (December 31, 2021 - $26.1 million). See Note 10 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2022	2021	2022	2021
Current tax expense/(recovery)	$ 12.0	$ 3.4	$ 17.0	$ 3.4
Deferred tax expense/(recovery)	71.7	(9.0)	81.5	(0.3)
Total tax expense/(recovery)	$ 83.7	$ (5.6)	$ 98.5	$ 3.1

For the three and six months ended June 30, 2022, we recorded a current tax expense of $12.0 million and $17.0 million, respectively, compared to $3.4 million recorded in 2021. The increase in current tax in 2022 is due to additional U.S. Federal and state tax resulting from higher expected 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 $90.00/bbl and NYMEX of $6.50/Mcf.

For the three and six months ended June 30, 2022, we recorded a deferred income tax expense of $71.7 million and $81.5 million, respectively, compared to a recovery of $9.0 million and $0.3 million for the same periods in 2021. The deferred tax expense in 2022 is due to higher income compared to the deferred tax recovery in 2021, primarily due to unrealized commodity derivative losses partially offset by U.S. 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 six months ended June 30, 2022, no valuation allowance was recorded against our U.S. or Canadian income related deferred tax assets, however, a full valuation allowance has been recorded against our deferred income tax assets related to capital items. Our overall net deferred income tax asset is $294.9 million as at June 30, 2022 (December 31, 2021 - $380.9 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, 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 six months, after which it drops to 3.0x. At June 30, 2022, our senior debt to adjusted EBITDA ratio was 0.6x and our net debt to adjusted funds flow ratio was 0.5x. 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 June 30, 2022 decreased to $546.0 million, compared to $640.4 million at December 31, 2021. Total debt was comprised of our senior notes and Bank Credit Facilities, totaling $571.4 million, less cash on hand of $25.4 million. During the six months ended June 30, 2022, we converted our senior unsecured, covenant-based $400 million term loan maturing on March 9, 2024 into a revolving bank credit facility, with no other amendments.

At June 30, 2022, through our Bank Credit Facilities, we had total credit capacity of $1.3 billion, of which $347.2 million was drawn. We expect to finance our working capital requirements and upcoming senior note repayments through cash, adjusted funds flow and our credit capacity. We have sufficient liquidity to meet our financial commitments for the near term.

Our reinvestment rate[1] was 45% and 41% for the three and six months ended June 30, 2022, respectively, compared to 71% and 63%, respectively, for the same periods in 2021.

During the three and six months ended June 30, 2022, a total of $102.8 million and $147.9 million, respectively, was returned to shareholders through share repurchases and dividends, compared to $9.1 million and $14.7 million for the same periods in 2021. During the three months ended June 30, 2022, a total of 7,078,222 common shares were repurchased and cancelled under the NCIB at an average price of $13.13 per share, for total consideration of $92.9 million. During the six months ended June 30, 2022, a total of 10,212,922 common shares were repurchased and cancelled under the NCIB at an average price of $12.74 per share, for total consideration of $130.1 million. We did not have a NCIB in place during the three and six months ended June 30, 2021.

Subsequent to June 30, 2022, the Company completed its current NCIB. In addition, the Board of Directors approved an increase to our 2022 return of capital plan to at least 60% of free cash flow[1], commencing in the second half of 2022 and continuing through 2023. We also increased the minimum 2022 return of capital commitment to $425 million, from $350 million previously. In connection with this plan, the Board of Directors has approved a renewal of the Company's NCIB to purchase another 10% of the public float during the following 12-month period and a 16% increase to the quarterly dividend to $0.05 per share, from $0.043 per share, beginning September 2022. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

At June 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.

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

Covenant Description		**June 30, 2022**
Bank Credit Facilities:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	0.6x
Total debt to adjusted EBITDA	4.0x	0.6x
Total debt to capitalization	55%	27%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.0x - 3.5x	0.6x
Senior debt to consolidated present value of total proved reserves(2)	60%	14%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	40.4x

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 June 30, 2022 was $315.3 million and $1,055.7 million, respectively.
"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $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 June 30,		Six months ended June 30,	
($ millions, except per share amounts)	2022	2021	2022	2021
Dividends(1)	$ 9.9	$ 9.1	$ 17.8	$ 14.7
Per weighted average share (Basic)	$ 0.043	$ 0.035	$ 0.076	$ 0.059

(1) Excludes changes in non-cash financing working capital. See Note 17 of the Interim Financial Statements for additional information.

During the three and six months ended June 30, 2022, we declared total dividends of $9.9 million, or $0.043 per share, and $17.8 million, or $0.076 per share, respectively, compared to $9.1 million, or $0.035 per share, and $14.7 million, or $0.059 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 increasing return of capital to shareholders.

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

Subsequent to June 30, 2022, the Board of Directors approved a 16% increase to the quarterly dividend to $0.05 per share, from $0.043 per share, beginning September 2022. We expect to fund the dividend through the free cash flow generated by the business.

Shareholders' Capital

	Six months ended June 30,	
	2022	**2021**
Share capital ($ millions)	$ 3,001.6	$ 3,222.7
Common shares outstanding (thousands)	234,879	256,750
Weighted average shares outstanding – basic (thousands)	241,022	250,443
Weighted average shares outstanding – diluted (thousands)	248,957	250,443

For the six months ended June 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 six months ended June 30, 2022, 10,212,922 common shares were repurchased and cancelled under the NCIB at an average price of $12.74 per share, for total consideration of $130.1 million. Of the amount paid, $100.4 million was charged to share capital and $29.7 million was credited to accumulated deficit. We did not have an NCIB in place during the three months and six months ended June 30, 2021. At June 30, 2022, 2,455,168 common shares were available for repurchase under the current NCIB.

Subsequent to June 30, 2022, we repurchased 2,455,168 common shares under the NCIB at an average price of $12.81 per common share, for total consideration of $31.5 million. The Company completed its current NCIB in July 2022. Subsequent to June 30, 2022, Enerplus received approval from the Board of Directors to renew its NCIB to purchase another 10% of the public float during the following 12-month period. The NCIB renewal remains subject to approval by the TSX.

At August 3, 2022, we had 232,424,289 common shares outstanding. In addition, an aggregate of 10,259,549 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.

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

SELECTED CANADIAN AND U.S.FINANCIAL RESULTS

	Three months ended June 30, 2022			Three months ended June 30, 2021		
($ millions, except per unit amounts)	U.S.	Canada	Total	U.S.	Canada	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	43,245	4,968	48,213	44,192	5,457	49,649
Natural gas liquids (bbls/day)	8,344	309	8,653	7,617	324	7,941
Natural gas (Mcf/day)	216,135	7,518	223,653	203,564	7,008	210,572
Total average daily production (BOE/day)	87,612	6,530	94,142	85,736	6,949	92,685
Pricing[(1)]						
Crude oil (per bbl)	$ 110.23	$ 96.10	$ 108.77	$ 63.51	$ 54.33	$ 62.50
Natural gas liquids (per bbl)	32.28	60.97	33.31	17.87	32.38	18.47
Natural gas (per Mcf)	6.10	6.55	6.11	1.93	2.89	1.96
Property, Plant and Equipment						
Capital and office expenditures	$ 131.6	$ 1.4	$ 133.0	$ 102.6	$ 3.7	$ 106.3
Acquisitions, including property and land	1.4	0.1	1.5	331.8	0.4	332.2
Property divestments	(8.6)	—	(8.6)	—	—	—
Netback Before Impact of Commodity Derivative Contracts[(2)]						
Crude oil and natural gas sales	$ 578.2	$ 49.8	$ 628.0	$ 303.5	$ 29.9	$ 333.4
Operating expenses	(72.4)	(11.0)	(83.4)	(60.8)	(11.3)	(72.1)
Transportation cost	(36.6)	(1.2)	(37.8)	(28.0)	(1.5)	(29.5)
Production taxes	(43.0)	(0.8)	(43.8)	(24.3)	(0.6)	(24.9)
Netback before impact of commodity derivative contracts	$ 426.2	$ 36.8	$ 463.0	$ 190.4	$ 16.5	$ 206.9
Other Expenses						
Commodity derivative instruments loss	$ —	$ 47.6	$ 47.6	$ —	$ 161.8	$ 161.8
General and administrative expense[(3)]	10.1	4.6	14.7	9.9	0.2	10.1
Current income tax expense	12.0	—	12.0	3.4	—	3.4

(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)	Six months ended June 30, 2022 U.S.	Canada	Total	Six months ended June 30, 2021 U.S.	Canada	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	42,839	5,086	47,925	36,333	5,590	41,923
Natural gas liquids (bbls/day)	8,213	303	8,516	6,259	354	6,613
Natural gas (Mcf/day)	212,933	7,467	220,400	200,167	8,106	208,273
Total average daily production (BOE/day)	86,541	6,633	93,174	75,952	7,296	83,248
Pricing(1)						
Crude oil (per bbl)	$ 102.07	$ 86.89	$ 100.46	$ 60.17	$ 49.54	$ 58.75
Natural gas liquids (per bbl)	34.71	56.69	35.49	21.97	31.17	22.46
Natural gas (per Mcf)	5.38	5.37	5.38	2.31	3.36	2.35
Property, Plant and Equipment						
Capital, office expenditures and line fill	$ 228.2	$ 4.1	$ 232.3	$ 152.0	$ 7.4	$ 159.4
Acquisitions, including property and land	2.6	0.8	3.4	828.0	1.3	829.3
Property divestments	(15.2)	—	(15.2)	—	(4.0)	(4.0)
Netback Before Impact of Commodity Derivative Contracts(2)						
Crude oil and natural gas sales	$ 1,050.5	$ 90.7	$ 1,141.2	$ 504.4	$ 57.4	$ 561.8
Operating expenses	(144.0)	(22.6)	(166.6)	(102.5)	(20.8)	(123.3)
Transportation cost	(71.2)	(2.4)	(73.6)	(52.1)	(3.3)	(55.4)
Production taxes	(77.8)	(1.4)	(79.2)	(37.7)	(1.0)	(38.7)
Netback before impact of commodity derivative contracts	$ 757.5	$ 64.3	$ 821.8	$ 312.1	$ 32.3	$ 344.4
Other Expenses						
Commodity derivative instruments loss	$ —	$ 254.4	$ 254.4	$ —	$ 218.1	$ 218.1
General and administrative expense(3)	17.7	14.6	32.3	17.4	5.6	23.0
Current income tax expense	17.0	—	17.0	3.4	—	3.4

(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				
Second Quarter	$ 628.0	$ 244.4	$ 1.01	$ 0.99
First Quarter	$ 513.2	$ 33.2	$ 0.14	$ 0.13
Total 2022	$ 1,141.2	$ 277.6	$ 1.15	$ 1.12
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 $628.0 million during the second quarter of 2022, compared to $513.2 million during the first quarter of 2022. The increase in crude oil and natural gas sales was a result of improved realized pricing and higher production during the second quarter of 2022 when compared to the first quarter of 2022. We reported net income of $244.4 million during the second quarter of 2022 compared to net income of $33.2 million during the first quarter of 2022. The increase was primarily due to a smaller loss recorded on commodity derivative instruments of $47.6 million during the second quarter of 2022, compared to a $206.8 million loss recorded in the first 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.

U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. At June 30, 2022, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2022 GUIDANCE

The following table summarizes our updated 2022 guidance and includes the impact of the recently announced sale of assets in Canada, which is expected to close at the end of the third quarter of 2022.

Summary of 2022 Annual Expectations	Target Annual Results
Capital spending ($ millions)	$400 - $440
Average annual production (BOE/day)	97,500 - 101,500 (from 96,000 - 101,000)
Average annual crude oil and natural gas liquids production (bbls/day)	59,500 - 62,500 (from 58,500 - 62,500)
Average production tax rate (% of net sales, before transportation)	7%
Operating expenses (per BOE)	$10.00 (from $9.75 - $10.50)
Transportation costs (per BOE)	$4.25 (from $4.15)
Cash G&A expenses (per BOE)	$1.20 (from $1.25)
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)	$1.00/bbl (from $0.00/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 months and six months ended June 30, 2022 and 2021. The calculation follows:

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2022	2021	2022	2021
Net income/(loss)	**$ 244.4**	**$ (50.9)**	**$ 277.6**	**$ (40.6)**
Unrealized commodity derivative instrument (gain)/loss	(91.3)	130.3	42.1	170.6
Asset impairment	—	—	—	3.4
Other expense related to investing activities	—	—	13.1	—
Unrealized foreign exchange (gain)/loss	(3.3)	6.8	(2.1)	7.0
Tax effect on above items	22.5	(31.5)	(12.6)	(41.9)
Adjusted net income/(loss)	**$ 172.3**	**$ 54.7**	**$ 318.1**	**$ 98.5**

"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 June 30,		Six months ended June 30,	
($ millions)	2022	2021	2022	2021
Cash flow from/(used in) operating activities	$ 250.9	$ 110.5	$ 446.9	$ 139.1
Asset retirement obligation settlements	2.3	1.2	11.1	6.8
Changes in non-cash operating working capital	44.2	38.3	101.3	104.9
Adjusted funds flow	**$ 297.4**	**$ 150.0**	**$ 559.3**	**$ 250.8**
Capital spending	(132.9)	(105.9)	(231.9)	(157.7)
Free cash flow	**$ 164.5**	**$ 44.1**	**$ 327.4**	**$ 93.1**

“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 June 30,		Six months ended June 30,	
($ millions)	2022	2021	2022	2021
Crude oil and natural gas sales	$ 628.0	$ 333.4	$ 1,141.2	$ 561.8
Less:				
Operating expenses	(83.4)	(72.1)	(166.6)	(123.3)
Transportation expenses	(37.8)	(29.5)	(73.6)	(55.4)
Production taxes	(43.8)	(24.9)	(79.2)	(38.7)
Netback before impact of commodity derivative contracts	**$ 463.0**	**$ 206.9**	**$ 821.8**	**$ 344.4**
Net realized gain/(loss) on derivative instruments	(138.2)	(31.0)	(211.3)	(46.4)
Netback after impact of commodity derivative contracts	**$ 324.8**	**$ 175.9**	**$ 610.5**	**$ 298.0**

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. For further details, see Note 8 to the Interim Financial Statements.

“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 June 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 April 1, 2022 and ended June 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: the recently announced sale of assets in Canada and the completion, timing, and anticipated benefits thereof; expected impact of the recently announced sale of assets in Canada on Enerplus' 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 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; expectations regarding payment of dividends and Enerplus' share repurchase program, including timing and amounts thereof and funding dividends and the share repurchase program from free cash flow; expectations regarding free cash flow generation and long-term capital spending reinvestment rates; expected operating strategy in 2022; anticipated impact of the recently announced sale of assets in Canada on Enerplus' future costs and expenses; 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 payment of increased dividends; expectations regarding our ability to comply with or renegotiate debt covenants under the Bank Credit Facilities and outstanding senior notes; our future acquisitions and dispositions; and expectations regarding renewal of our NCIB, including timing, size, and regulatory approval thereof.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: the benefits of the recently announced sale of assets in Canada; that Enerplus will realize the expected impact of the recently announced sale of assets in Canada; 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 ability to fund increased dividend payments and the share purchase program from free cash flow as expected and discussed in this MD&A; the ability of Enerplus to obtain regulatory approval for its NCIB renewal in a timely manner and pursuant to the terms thereof; our ability to comply with our debt covenants; 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 $90.00/bbl, a NYMEX price of $6.50/Mcf, a Bakken crude oil price differential of $1.00/bbl above WTI, a Marcellus natural gas price differential of $0.75/Mcf below NYMEX and a CDN/USD exchange rate of $0.78.

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 realize anticipated benefits of the recently announced sale of assets in Canada; continued instability, or further deterioration, in global economic and market environment, including from COVID-19, 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; 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.