Exhibit 99.1

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

The following discussion and analysis of financial results is dated November 2, 2023 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, 2023 and 2022 (the "Interim Financial Statements") and notes thereto;
- the audited consolidated financial statements of Enerplus at December 31, 2022 and 2021 and for the years ended December 31, 2022, 2021 and 2020; and
- the MD&A for the year ended December 31, 2022 (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, 2022 (the "Annual Information Form").

BASIS OF PRESENTATION

The Interim Financial Statements and notes thereto have been prepared in accordance with U.S. GAAP. Unless otherwise stated, all dollar amounts are presented in U.S. dollars. Certain prior period amounts have been restated to conform with current period presentation as a result of the voluntary and retroactively applied change in the presentation currency from Canadian to U.S. dollars adopted by the Company in the fourth quarter of 2021.

The functional currency of the parent company changed from Canadian dollars to U.S. dollars effective January 1, 2023. This was the result of a gradual change in the primary economic environment in which the entity operates, culminating in the sale of Enerplus' remaining Canadian operating assets at the end of 2022. This has triggered a prospective change as of January 1, 2023 in functional currency of the parent entity to U.S. dollars, consistent with the functional currency of its U.S. subsidiaries. All assets and liabilities held by the parent company were translated at the exchange rate at December 31, 2022 to determine opening balances in U.S. dollars. Amounts that are part of Shareholders' Equity of the parent company were translated at historical exchange rates. Monetary assets and liabilities denominated in Canadian dollars will be revalued at current exchange rates at each reporting period. Upon settlement and/or realization of Canadian dollar denominated assets and liabilities, there may be realized foreign exchange gains and losses depending on the change in the foreign exchange rate when the transaction was originally recorded and the final settlement date.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE 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 Mcfe. The BOE and Mcfe rates 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.

In accordance with U.S. GAAP, crude oil and natural gas sales are presented net of royalties in the Financial Statements. In addition, unless otherwise noted, all production volumes are 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.

All references to "liquids" in this MD&A include light and medium 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

Crude oil and natural gas liquids production increased by 14% to 66,625 BOE/day during the third quarter of 2023, compared to the second quarter of 2023, primarily due to strong well performance from additional wells coming on-stream in North Dakota. Total production during the third quarter of 2023 averaged 103,192 BOE/day, an increase of 8% compared to average production of 95,572 BOE/day in the second quarter of 2023. As a result, we are increasing our average annual production guidance for 2023 to 98,000 BOE/day - 99,000 BOE/day, including 60,500 bbls/day - 61,500 bbls/day of crude oil and natural gas liquids, from 94,500 BOE/day - 98,500 BOE/day, including 58,500 bbls/day - 61,500 bbls/day of crude oil and natural gas liquids. For the fourth quarter of 2023, we expect average production of 95,000 BOE/day - 99,000 BOE/day, including 60,500 bbls/day - 64,500 bbls/day of crude oil and natural gas liquids.

During the third quarter of 2023, a total of $67.7 million was returned to shareholders through share repurchases and dividends, an increase from $66.5 million in the second quarter of 2023. As previously announced, we plan to return at least 60% of second half 2023 free cash flow[1] to our shareholders, which is expected to result in over 70% of full year 2023 free cash flow returned. In conjunction with this plan, the Board of Directors approved a fourth quarter dividend of $0.06 per share to be paid in December 2023. The Company expects to continue to return significant free cash flow to shareholders in 2024 and anticipates its return of capital will equal approximately 70% of free cash flow. The Company expects to continue to prioritize share repurchases for the majority of its return of capital plan, based on current market conditions. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

Capital spending during the third quarter of 2023 was $121.4 million, compared to $180.9 million during the second quarter of 2023, with the majority of the spending focused on our U.S. crude oil properties. The decrease in capital spending was due to less completions activity during the third quarter of 2023. We are narrowing our annual capital spending guidance for 2023 to range between $520 - $540 million from $510 - $550 million.

Our realized Bakken crude oil price differential averaged $0.20/bbl above WTI during the third quarter of 2023, compared to $0.71/bbl below WTI during the second quarter of 2023. The stronger realized differential was due to higher prices for crude oil delivered to downstream markets in both Patoka and the U.S. Gulf Coast via the Dakota Access Pipeline combined with a recovery in WTI prices throughout the summer. Additionally, U.S. refinery utilizations and margins remained strong throughout the third quarter of 2023. Bakken crude oil prices have weakened in the fourth quarter of 2023 due to increased basin production and lower seasonal refinery demand resulting from planned maintenance outages. As a result, we are revising our 2023 expected annual realized Bakken crude oil price differential to $0.25/bbl below WTI, from a crude oil price differential at par to WTI, previously.

Our realized Marcellus sales price differential averaged $1.24/Mcf below NYMEX in the third quarter of 2023 compared to $0.68/Mcf below NYMEX in the second quarter of 2023. The wider differential was mainly due to increased supply in the northeast U.S. and regional storage levels tracking above historical averages. As a result of weaker expected realized differentials, we are revising our 2023 expected annual realized Marcellus natural gas differential to average $0.85/Mcf below NYMEX, from a natural gas differential of $0.75/Mcf below NYMEX, previously.

Operating expenses for the third quarter of 2023 increased to $96.6 million, or $10.17/BOE, compared to $89.1 million, or $10.25/BOE during the second quarter of 2023. The increase in total spend was due to higher production as a result of new wells brought on stream during the second and third quarters of 2023. We continue to expect operating expenses in the fourth quarter of 2023 to increase compared to the third quarter of 2023, due to planned workover activity. As a result, we are revising our operating expenses guidance for 2023 to range between $10.75/BOE - $11.00/BOE from $10.75/BOE - $11.50/BOE.

We reported net income of $127.7 million in the third quarter of 2023, compared to net income of $74.2 million in the second quarter of 2023. Net income increased primarily due to higher commodity prices and crude oil and natural gas liquids production in the third quarter of 2023.

In the third quarter of 2023, cash flow from operating activities and adjusted funds flow increased to $212.2 million and $263.7 million, respectively, compared to $186.6 million and $196.6 million in the second quarter of 2023. The increase was primarily due to higher commodity prices and crude oil and natural gas liquids production in the third quarter of 2023.

At September 30, 2023, net debt increased to $212.1 million, compared to $199.6 million at June 30, 2023. Net debt is calculated as total debt, which was comprised of our senior notes and borrowing on our $900 million sustainability linked lending (“SLL”) bank credit facility and our $365 million SLL bank credit facility (together referred to as the “Bank Credit Facilities”), less cash on hand of $46.2 million. Net debt increased primarily due to working capital changes, as our non-cash operating and investing working capital deficit changed by approximately $85.0 million in the third quarter of 2023. At September 30, 2023, a total of $135.7 million was drawn on our Bank Credit Facilities. Our net debt to adjusted funds flow ratio was 0.2x, which remains consistent with the second quarter of 2023.

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

RESULTS OF OPERATIONS

Production

Crude oil and natural gas liquids production increased by 14% during the third quarter of 2023, compared to the second quarter of 2023, primarily due to 17.2 net operated and 3.3 net non-operated wells coming on-stream in North Dakota. The increase in crude oil and natural gas production was partially offset by a 6% decrease in natural gas production in the Marcellus as a result of limited capital investment during 2023. As a result, total production during the third quarter of 2023 averaged 103,192 BOE/day, an increase of 8% compared to average production of 95,572 BOE/day in the second quarter of 2023.

Production decreased for the three months ended September 30, 2023 compared to the same period in 2022, due to the sale of substantially all of our Canadian assets in the fourth quarter of 2022, and a decrease in natural gas production in the Marcellus as a result of limited capital investment during 2023. Production for the nine months ended September 30, 2023, increased compared to the same period in 2022 due to strong well performance from new wells brought online, and an increase in gas capture which contributed to higher natural gas liquids and natural gas production volumes in North Dakota, partially offset by the sale of our Canadian assets in the fourth quarter of 2022.

Our crude oil and natural gas liquids weighting increased to 65% from 63% for the three months ended September 30, 2023 and decreased to 61% from 62% for the nine months ended September 30, 2023, compared to the same periods in 2022.

We are increasing our average annual total production guidance for 2023 to 98,000 BOE/day - 99,000 BOE/day, including 60,500 bbls/day - 61,500 bbls/day of crude oil and natural gas liquids, from 94,500 BOE/day - 98,500 BOE/day, including 58,500 bbls/day - 61,500 bbls/day of crude oil and natural gas liquids. For the fourth quarter of 2023, we expect average production of 95,000 BOE/day - 99,000 BOE/day, including 60,500 bbls/day - 64,500 bbls/day of crude oil and natural gas liquids.

Average daily production volumes for the three and nine months ended September 30, 2023 and 2022 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2023**	**2022**	**% Change**	**2023**	**2022**	**% Change**
Tight oil (bbls/day)	54,195	52,793	3%	49,690	46,194	8%
Light and medium oil (bbls/day)	—	2,038	(100%)	—	2,097	(100%)
Heavy oil (bbls/day)	—	2,651	(100%)	—	2,855	(100%)
Total crude oil (bbls/day)	54,195	57,482	(6%)	49,690	51,146	(3%)
Natural gas liquids (bbls/day)	12,430	10,900	14%	10,871	9,319	17%
Shale gas - Marcellus (Mcf/day)	144,523	164,731	(12%)	159,509	164,843	(3%)
Shale gas - Bakken (Mcf/day)	74,878	64,918	15%	70,082	53,863	30%
Conventional natural gas (Mcf/day)	—	6,909	(100%)	—	7,139	(100%)
Total natural gas (Mcf/day)	219,401	236,558	(7%)	229,591	225,845	2%
Total daily sales (BOE/day)	103,192	107,808	(4%)	98,826	98,106	1%

Pricing

The prices received for crude oil, natural gas liquids 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, 2023	Nine months ended September 30, 2022	Q3 2023	Q2 2023	Q1 2023	Q4 2022	Q3 2022
Benchmarks							
WTI crude oil ($/bbl)	$ 77.39	$ 98.09	$ 82.26	$ 73.78	$ 76.13	$ 82.65	$ 91.56
Brent (ICE) crude oil ($/bbl)	82.06	102.33	85.95	78.01	82.22	88.60	97.81
Propane – Conway ($/bbl)	29.56	49.98	27.98	27.70	32.99	34.21	44.73
NYMEX natural gas – last day ($/Mcf)	2.69	6.77	2.55	2.10	3.42	6.26	8.20
CDN/US average exchange rate	0.74	0.78	0.74	0.74	0.74	0.74	0.77
CDN/US period end exchange rate	0.74	0.72	0.74	0.76	0.74	0.74	0.72
Enerplus selling price(1)							
Crude oil ($/bbl)	$ 77.50	$ 97.44	$ 82.66	$ 72.69	$ 76.34	$ 83.06	$ 92.48
Natural gas liquids ($/bbl)	18.36	34.13	19.21	15.49	20.55	21.88	32.04
Natural gas ($/Mcf)	1.91	5.79	1.37	1.08	3.18	4.76	6.53
Average differentials							
Bakken DAPL – WTI ($/bbl)	$ 0.94	$ 2.43	$ 0.73	$ 0.78	$ 1.32	$ 3.19	$ 3.60
Brent (ICE) – WTI ($/bbl)	4.67	4.24	3.69	4.23	6.09	5.95	6.25
Transco Leidy monthly – NYMEX ($/Mcf)	(0.88)	(0.89)	(1.47)	(0.63)	(0.54)	(1.51)	(1.06)
Transco Z6 Non-New York monthly – NYMEX ($/Mcf)	0.47	(0.10)	(1.36)	(0.57)	3.35	(0.20)	(0.85)
Enerplus realized differentials(1)(2)							
Bakken crude oil – WTI ($/bbl)	$ (0.16)	$ 1.07	$ 0.20	$ (0.71)	$ 0.06	$ 1.05	$ 2.41
Marcellus natural gas – NYMEX ($/Mcf)	(0.83)	(0.53)	(1.24)	(0.68)	(0.64)	(1.18)	(0.99)

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

CRUDE OIL

During the third quarter of 2023, our realized crude oil sales price averaged $82.66/bbl, an increase of 14% compared to the second quarter of 2023, in line with the increases in the underlying benchmark WTI price and Bakken differentials over the same period. WTI prices increased through the third quarter of 2023 due to strong demand for refined products during the peak summer consumption period as well as additional voluntary production cuts by Saudi Arabia and Russia through the end of the year.

Our realized Bakken crude oil price differential averaged $0.20/bbl above WTI during the third quarter of 2023, compared to $0.71/bbl below WTI during the second quarter of 2023. The stronger realized differential was due to higher prices for crude oil delivered to downstream markets in both Patoka and the U.S. Gulf Coast via the Dakota Access Pipeline combined with a recovery in WTI prices throughout the summer. Additionally, U.S. refinery utilizations and margins remained strong throughout the third quarter of 2023. Bakken crude oil prices have weakened in the fourth quarter of 2023 due to increased basin production and lower seasonal refinery demand resulting from planned maintenance outages. As a result, we are revising our 2023 expected annual realized Bakken crude oil price differential to $0.25/bbl below WTI, from a crude oil price differential at par to WTI, previously.

NATURAL GAS LIQUIDS

Our realized sales price for natural gas liquids averaged $19.21/bbl during the third quarter of 2023 compared to $15.49/bbl during the second quarter of 2023. The improved realized differentials were primarily due to an adjustment in our overall natural gas liquids composition due to wells coming on stream in the Little Knife area. Propane price weakness continued during the third quarter of 2023 due to high inventories, growing production, and reliance on exports to balance the North American market. Benchmark propane pricing at Conway remained flat, even as prices rose for other energy products.

NATURAL GAS

Our realized natural gas sales price averaged $1.37/Mcf during the third quarter of 2023, an increase of 27% compared to the second quarter of 2023. The NYMEX benchmark price increased by 21% over the same period. The difference in price realization versus the benchmark was due to stronger regional prices received for our Bakken natural gas production, which offset weakness in Marcellus regional prices.

Our realized Marcellus sales price differential averaged $1.24/Mcf below NYMEX in the third quarter of 2023 compared to $0.68/Mcf below NYMEX in the second quarter of 2023. The wider differential was mainly due to increased supply in the northeast U.S. and regional storage levels tracking above historical averages. As a result of weaker expected realized differentials, we are revising our 2023 expected annual realized Marcellus natural gas differential to average $0.85/Mcf below NYMEX, from a natural gas differential of $0.75/Mcf below NYMEX, previously.

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. At November 1, 2023, we have hedged 10,000 bbls/day of WTI crude oil price exposure for the remainder of 2023. Additionally, we have hedged 5,000 bbls/day of WTI crude oil price exposure for the period January 1, 2024 to June 30, 2024. Our crude oil contracts include 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 table summarizes Enerplus' price risk management positions at September 30, 2023, and positions entered into subsequent to September 30, 2023 and up to November 1, 2023:

	WTI Crude Oil ($/bbl)(1)(2)		NYMEX Natural Gas ($/Mcf)(2)
	Oct 1, 2023 – Dec 31, 2023	Jan 1, 2024 – Jun 30, 2024	Oct 1, 2023 – Oct 31, 2023
Swaps			
Volume (bbls/day)	10,000	–	–
Brent - WTI Spread	$ 5.47	–	–
3 Way Collars			
Volume (bbls/day)	10,000	5,000	–
Sold Puts	$ 65.00	$ 65.00	–
Purchased Puts	$ 81.00	$ 77.00	–
Sold Calls	$ 111.58	$ 95.00	–
Collars			
Volume (Mcf/day)	–	–	50,000
Volume (bbls/day)(3)	2,000	–	–
Purchased Puts	$ 5.00	–	$ 4.05
Sold Calls	$ 75.00	–	$ 7.00

(1) The total average deferred premium spent on our outstanding crude oil contracts is $1.19/bbl from October 1, 2023 – June 30, 2024.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Outstanding commodity derivative instruments acquired as part of the Company's acquisition of Bruin E&P Holdco, LLC completed in 2021.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2023	2022	2023	2022
Realized gains/(losses):				
Crude oil	$ (1.6)	$ (50.5)	$ 7.1	$ (233.1)
Natural gas	6.9	(38.0)	46.7	(66.7)
Total realized gains/(losses)	$ 5.3	$ (88.5)	$ 53.8	$ (299.8)
Unrealized gains/(losses):				
Crude oil	$ (14.0)	$ 126.0	$ (8.8)	$ 98.8
Natural gas	(5.9)	19.5	(24.7)	3.6
Total unrealized gains/(losses)	$ (19.9)	$ 145.5	$ (33.5)	$ 102.4
Total commodity derivative instruments gains/(losses)	$ (14.6)	$ 57.0	$ 20.3	$ (197.4)

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2023	2022	2023	2022
Total realized gains/(losses)	$ 0.56	$ (8.92)	$ 1.99	$ (11.19)
Total unrealized gains/(losses)	(2.10)	14.67	(1.24)	3.82
Total commodity derivative instruments gains/(losses)	$ (1.54)	$ 5.75	$ 0.75	$ (7.37)

During the three and nine months ended September 30, 2023, Enerplus realized a loss of $1.6 million and a gain of $7.1 million, respectively, on our crude oil contracts, compared to realized losses of $50.5 million and $233.1 million for the same periods in 2022. For the three and nine months ended September 30, 2023, realized gains of $6.9 million and $46.7 million, respectively, were recorded on our natural gas contracts, compared to realized losses of $38.0 million and $66.7 million for the same periods in 2022. Realized gains recorded during the three and nine months ended September 30, 2023 were due to natural gas commodity prices falling below the purchased put 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, 2023, the fair value of our crude oil and natural gas contracts was in a net liability position of $5.3 million (December 31, 2022 – net asset position of $26.1 million). For the three and nine months ended September 30, 2023, the change in the fair value of our crude oil contracts resulted in unrealized losses of $14.0 million and $8.8 million, respectively, compared to unrealized gains of $126.0 million and $98.8 million, during the same periods in 2022. For the three and nine months ended September 30, 2023, we recorded unrealized losses on our natural gas contracts of $5.9 million and $24.7 million, respectively, compared to unrealized gains of $19.5 million and $3.6 million, during the same periods in 2022.

Crude Oil and Natural Gas Sales

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2023	2022	2023	2022
Crude oil and natural gas sales	$ 461.8	$ 663.5	$ 1,226.0	$ 1,804.7
Per BOE	$ 48.65	$ 66.90	$ 45.44	$ 67.38

Crude oil and natural gas sales for the three and nine months ended September 30, 2023 were $461.8 million, or $48.65/BOE, and $1,226.0 million, or $45.44/BOE, respectively, compared to $663.5 million, or $66.90/BOE, and $1,804.7 million, or $67.38/BOE, for the same periods in 2022. The decrease in crude oil and natural gas sales was primarily due to lower commodity prices and Marcellus production during the three and nine months ended September 30, 2023, and the impact of the Canadian divestments completed in the fourth quarter of 2022.

Operating Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2023	2022	2023	2022
Operating expenses	$ 96.6	$ 103.8	$ 278.5	$ 270.5
Per BOE	$ 10.17	$ 10.47	$ 10.32	$ 10.10

For the three and nine months ended September 30, 2023, operating expenses were $96.6 million, or $10.17/BOE, and $278.5 million, or $10.32/BOE, respectively, compared to $103.8 million, or $10.47/BOE, and $270.5 million, or $10.10/BOE, for the same periods in 2022. During the three months ended September 30, 2023, the decrease was due to the impact of the Canadian divestments completed in the fourth quarter of 2022, partially offset by higher gas facility charges and lower natural gas production in the Marcellus which has lower associated operating expenses. During the nine months ended September 30, 2023, the increase was due to inflation adjusted contract pricing and lower natural gas production in the Marcellus, offset by the Canadian divestments completed in the fourth quarter of 2022.

We continue to expect operating expenses in the fourth quarter of 2023 to increase compared to the third quarter of 2023, due to planned workover activity. We are revising our operating expenses guidance for 2023 to range between $10.75/BOE - $11.00/BOE from $10.75/BOE - $11.50/BOE.

Transportation Costs

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2023	2022	2023	2022
Transportation costs	$ 36.7	$ 41.3	$ 108.9	$ 114.9
Per BOE	$ 3.87	$ 4.16	$ 4.04	$ 4.29

For the three and nine months ended September 30, 2023, transportation costs were $36.7 million, or $3.87/BOE, and $108.9 million, or $4.04/BOE, respectively, compared to $41.3 million, or $4.16/BOE, and $114.9 million, or $4.29/BOE for the same periods in 2022. The decrease was due to a higher proportion of total production volumes from areas with lower associated transportation costs, offset by the impact of the Canadian divestments in the fourth quarter of 2022.

We are revising our transportation costs guidance for 2023 to $4.05/BOE from $4.20/BOE.

Production Taxes

($ millions, except per BOE amounts)	Three months ended September 30, 2023	Three months ended September 30, 2022	Nine months ended September 30, 2023	Nine months ended September 30, 2022
Production taxes	$ 40.0	$ 48.2	$ 98.8	$ 127.4
Per BOE	$ 4.21	$ 4.86	$ 3.65	$ 4.76
Production taxes (% of crude oil and natural gas sales)	8.7%	7.3%	8.1%	7.1%

Production taxes for the three and nine months ended September 30, 2023, were $40.0 million, or 8.7%, and $98.8 million, or 8.1%, respectively, compared to $48.2 million, or 7.3%, and $127.4 million, or 7.1% for the same periods in 2022. The decrease in total production taxes for the three and nine months ended September 30, 2023, was primarily due to lower realized prices and higher effective tax rates on U.S. crude oil during June to October 2022 as WTI based pricing exceeded certain thresholds. The increase in production tax as a percentage of revenue for the three and nine months ended September 30, 2023 was due to increased U.S. crude oil production which has higher rates of production tax combined with decreased natural gas and natural gas liquids revenues with lower associated production taxes, compared to the same periods in 2022.

We continue to expect production taxes to average 8% in 2023.

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, 2023		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	79,100 BOE/day	144,549 Mcfe/day	103,192 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 61.07	$ 1.31	$ 48.65
Operating expenses	(12.93)	(0.19)	(10.17)
Transportation costs	(3.37)	(0.92)	(3.87)
Production taxes	(5.40)	(0.05)	(4.21)
Netback before impact of commodity derivative contracts	$ 39.37	$ 0.15	$ 30.40
Realized gains/(losses) on commodity derivative contracts	(0.22)	0.52	0.56
Netback after impact of commodity derivative contracts	$ 39.15	$ 0.67	$ 30.96
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 286.5	$ 2.0	$ 288.5
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 284.9	$ 8.9	$ 293.8

(1) This financial measure is a non-GAAP financial measure. See "Non-GAAP Measures" section in 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 gains/(losses) on commodity derivative contracts	(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)	$ 325.5	$ 56.2	$ 381.7

(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, 2023 Crude Oil	Natural Gas	Total
Average Daily Production	72,209 BOE/day	159,702 Mcfe/day	98,826 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 57.98	$ 1.91	$ 45.44
Operating expenses	(13.72)	(0.19)	(10.32)
Transportation costs	(3.54)	(0.90)	(4.04)
Production taxes	(4.94)	(0.03)	(3.65)
Netback before impact of commodity derivative contracts	$ 35.78	$ 0.79	$ 27.43
Realized gains/(losses) on commodity derivative contracts	0.36	1.07	1.99
Netback after impact of commodity derivative contracts	$ 36.14	$ 1.86	$ 29.42
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 705.4	$ 34.4	$ 739.8
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 712.4	$ 81.2	$ 793.6

(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 gains/(losses) on commodity derivative contracts	(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.

Total netbacks before and after the impact of commodity derivative contracts for the three and nine months ended September 30, 2023 were lower compared to the same periods in 2022, due to lower realized commodity prices.

For the three and nine months ended September 30, 2023, crude oil properties accounted for 99% and 95%, respectively, of total netback before commodity derivative contracts, compared to 80% and 82% during the same periods in 2022, as a result of lower realized natural gas prices in 2023.

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, 2023	2022	Nine months ended September 30, 2023	2022
Cash:				
G&A expenses	$ 12.1	$ 10.9	$ 35.4	$ 31.5
Share-based compensation expense/(recovery)	1.9	1.2	1.1	3.6
Non-Cash:				
Share-based compensation expense/(recovery)	5.0	3.8	17.2	14.3
Equity swap gain	—	—	—	(1.0)
G&A recovery	(0.1)	(0.1)	(0.3)	(0.3)
Total G&A expenses	$ 18.9	$ 15.8	$ 53.4	$ 48.1

(Per BOE)	Three months ended September 30, 2023	2022	Nine months ended September 30, 2023	2022
Cash:				
G&A expenses	$ 1.27	$ 1.10	$ 1.31	$ 1.18
Share-based compensation expense/(recovery)	0.20	0.12	0.04	0.13
Non-Cash:				
Share-based compensation expense/(recovery)	0.53	0.38	0.64	0.53
Equity swap gain	—	—	—	(0.04)
G&A recovery	(0.01)	(0.01)	(0.01)	(0.01)
Total G&A expenses	$ 1.99	$ 1.59	$ 1.98	$ 1.79

Cash G&A expenses for the three and nine months ended September 30, 2023 were $12.1 million, or $1.27/BOE, and $35.4 million, or $1.31/BOE, respectively, compared to $10.9 million, or $1.10/BOE, and $31.5 million, or $1.18/BOE, for the same periods in 2022. Total cash G&A expenses increased primarily 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. Cash-settled SBC for the three and nine months ended September 30, 2023, was an expense of $1.9 million, or $0.20/BOE, and an expense of $1.1 million, or $0.04/BOE, respectively, compared to expenses of $1.2 million, or $0.12/BOE, and $3.6 million, or $0.13/BOE, for the same periods in 2022, and relates to our director plans. The large expense in 2022 was due to a significant increase in Enerplus' share price from 2021.

Equity-settled non-cash SBC for the three and nine months ended September 30, 2023, was $5.0 million, or $0.53/BOE, and $17.2 million, or $0.64/BOE, respectively, compared to $3.8 million, or $0.38/BOE, and $14.3 million, or $0.53/BOE, for the same periods in 2022. Performance Share Units ("PSUs"), as one of the equity-settled LTI plans, are impacted by performance multipliers. For the three months ended September 30, 2023, the increase was due to the applicable multipliers being higher compared to the same period in 2022. For the nine months ended September 30, 2023, the increase was due to additional expense for retirement eligible individuals, compared to the same period in 2022.

Enerplus previously had hedged a portion of the outstanding cash-settled units under its LTI plans. During the nine months ended September 30, 2022, we recorded a mark-to-market gain of $1.0 million as a result of higher share prices. Enerplus settled its equity derivative contracts during 2022 and did not have any equity derivatives outstanding at September 30, 2023.

We continue to expect cash G&A expenses of $1.35/BOE in 2023.

Interest Expense

For the three and nine months ended September 30, 2023, we recorded a total interest expense of $4.8 million and $12.7 million, respectively, compared to $6.5 million and $18.6 million for the same periods in 2022. The decrease was primarily due to lower debt levels during the three and nine months ended September 30, 2023, compared to the same period in 2022, as lower debt levels were sustained throughout 2023.

At September 30, 2023, $135.7 million was drawn on the Bank Credit Facilities. At September 30, 2023, approximately 47% of our debt was based on fixed interest rates and 53% on floating interest rates (December 31, 2022 – 78%, 22%), with a weighted average interest rate of 4.1% and 6.6%, respectively (December 31, 2022 – 4.1%, 5.7%).

Foreign Exchange

($ millions)	Three months ended September 30, 2023		Three months ended September 30, 2022		Nine months ended September 30, 2023		Nine months ended September 30, 2022	
Realized:								
Foreign exchange (gain)/loss	$	(0.1)	$	0.1	$	(0.2)	$	—
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company		—		(1.0)		—		(1.1)
Unrealized:								
Foreign exchange (gain)/loss on Canadian dollar working capital in parent company		0.7		—		(0.1)		—
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company		—		17.0		—		14.9
Total foreign exchange (gain)/loss	$	0.6	$	16.1	$	(0.3)	$	13.8
CDN/US average exchange rate		0.74		0.77		0.74		0.78
CDN/US period end exchange rate		0.74		0.72		0.74		0.72

For the three and nine months ended September 30, 2023, Enerplus recorded a foreign exchange loss of $0.6 million and a gain of $0.3 million, respectively, compared to gains of $16.1 million and $13.8 million for the same periods in 2022. The decrease for the three and nine months ended September 30, 2023, was due to Enerplus previously recording unrealized foreign exchange gains and losses on the translation of our U.S. dollar denominated working capital held in Canada at each period-end, prior to the functional currency change of the parent company to U.S. dollars on January 1, 2023.

Enerplus is exposed to foreign exchange risk as it relates to certain activities transacted in Canadian dollars. The parent company and its subsidiaries have a U.S. dollar functional currency, and the parent company has both U.S. and Canadian dollar transactions. Canadian denominated monetary assets and liabilities are subject to revaluation from the source currency of Canadian dollars to the functional currency of U.S. dollars, generating realized and unrealized foreign exchange (gains)/losses in the Condensed Consolidated Statements of Income/(Loss). For the three and nine months ended September 30, 2022, Enerplus recorded unrealized foreign exchange losses of $17.0 million and $14.9 million, respectively, due to the impact of the weaker Canadian dollar on the U.S. dollar-denominated working capital held in the parent company, which had a Canadian dollar functional currency until December 31, 2022.

Following the change in functional currency of the parent company to U.S. dollars on January 1, 2023, the net investment hedge on the U.S. dollar denominated debt held in the parent entity for the U.S. subsidiaries was no longer required. Previously, the unrealized foreign exchange gains and losses arising from the translation of the debt were recorded in Other Comprehensive Income/(Loss), net of tax, and were limited by the cumulative translation gain or loss on the net investment in the U.S. subsidiaries. For the three and nine months ended September 30, 2023, there were no unrealized foreign exchange gains or losses recorded in Other Comprehensive Income/(Loss) compared to unrealized losses of $24.3 million and $33.0 million, respectively, for the same periods in 2022, on Enerplus' U.S. dollar denominated senior notes and Bank Credit Facilities.

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

($ millions)	Three months ended September 30, 2023		Three months ended September 30, 2022		Nine months ended September 30, 2023		Nine months ended September 30, 2022	
Capital spending(1)	$	121.4	$	114.5	$	440.9	$	346.4
Office capital		1.3		0.2		2.6		0.6
Sub-total		122.7		114.7		443.5		347.0
Property and land acquisitions		2.3		16.3		5.7		19.7
Property and land divestments(1)		(1.6)		(4.2)		(1.7)		(19.4)
Sub-total		0.7		12.1		4.0		0.3
Total	$	123.4	$	126.8	$	447.5	$	347.3

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

Capital spending for the three and nine months ended September 30, 2023 totaled $121.4 million and $440.9 million, respectively, compared to $114.5 million and $346.4 million for the same periods in 2022. The increase was mainly due to increased capital activity on our North Dakota properties offset by minimal capital investment on our Marcellus natural gas properties.

Property and land acquisitions for the three and nine months ended September 30, 2023, were $2.3 million and $5.6 million, respectively, compared to $16.3 million and $19.7 million for the same periods in 2022. Property and land acquisitions during both periods were primarily related to the acquisition of interests in North Dakota.

Property and land divestments for the three and nine months ended September 30, 2023, were $1.6 million and $1.7 million, respectively, compared to $4.2 million and $19.4 million for the same periods in 2022. Property and land divestments for the nine months ended September 30, 2022 related to the sale of minor non-operated interests in North Dakota and Colorado.

We are narrowing our annual capital spending guidance range for 2023 to $520 - $540 million from $510 - $550 million.

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2023	2022	2023	2022
DD&A expense	$ 91.8	$ 82.2	$ 264.1	$ 219.0
Per BOE	$ 9.67	$ 8.29	$ 9.79	$ 8.18

DD&A related to PP&E is recognized using the unit of production method based on proved reserves. For the three and nine months ended September 30, 2023, Enerplus recorded DD&A expense of $91.8 million, or $9.67/BOE, and $264.1 million, or $9.79/BOE, respectively, compared to $82.2 million, or $8.29/BOE, and $219.0 million, or $8.18/BOE for the same periods in 2022. The increase was primarily a result of reserve additions and revisions at December 31, 2022 and subsequent capital spending in 2023.

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 $117.9 million at September 30, 2023, compared to $114.7 million at December 31, 2022.

For the three and nine months ended September 30, 2023, ARO settlements were $2.4 million and $11.3 million, respectively, compared to $1.6 million and $12.7 million during the same periods in 2022.

During 2022, Enerplus benefited from provincial government assistance to support the clean-up of inactive or abandoned crude oil and natural gas wells. These programs provided direct funding to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. The funding received by the contractor was reflected as a reduction to ARO.

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2023	2022	2023	2022
Current tax expense	$ 12.5	$ 7.9	$ 27.0	$ 24.9
Deferred tax expense	25.6	93.1	70.6	174.6
Total tax expense	$ 38.1	$ 101.0	$ 97.6	$ 199.5

For the three and nine months ended September 30, 2023, we recorded a current tax expense of $12.5 million and $27.0 million, respectively, compared to $7.9 million and $24.9 million for the same periods in 2022. Current tax expense in 2023 was higher compared to 2022 as a result of utilizing all of our net operating losses in 2022. Many factors influence taxable income, including future commodity prices, production levels, development activities, capital spending, and overall profitability. We continue to expect 2023 cash tax of 3.0% – 4.0% of adjusted funds flow before tax based on guidance pricing.

For the three and nine months ended September 30, 2023, we recorded a deferred income tax expense of $25.6 million and $70.6 million, respectively, compared to an expense of $93.1 million and $174.6 million for the same periods in 2022. Deferred tax expense was lower in 2023 compared to 2022 due to a decrease in net 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, 2023, 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 was $143.1 million, and the deferred income tax liability recorded in the U.S. was $114.1 million as at September 30, 2023. (December 31, 2022 - $155.0 million deferred income tax asset in Canada and $55.4 million deferred income tax liability in the U.S.).

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, 2023, our senior debt to adjusted EBITDA ratio was 0.2x and our net debt to adjusted funds flow ratio was 0.2x. 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, 2023 decreased to $212.1 million, compared to $221.5 million at December 31, 2022. Net debt was comprised of our senior notes and Bank Credit Facilities totaling $258.3 million, less cash on hand of $46.2 million.

At September 30, 2023, our Bank Credit Facilities totaled $1.3 billion, of which $135.7 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.

Our reinvestment rate[1] was 46% and 61% for the three and nine months ended September 30, 2023, respectively, compared to 32% and 38% for the same periods in 2022.

During the nine months ended September 30, 2023, a total of $200.8 million was returned to shareholders through share repurchases and dividends, compared to $271.3 million for the same period in 2022. During the nine months ended September 30, 2023, a total of 10.6 million common shares were repurchased and cancelled under the Normal Course Issuer Bid ("NCIB") at an average price of $15.50 per share, for total consideration of $164.4 million. During the nine months ended September 30, 2022, a total of 18.1 million 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.

Subsequent to September 30, 2023 and up to November 1, 2023, we repurchased 2.5 million common shares under the NCIB at an average price of $16.65 per share, for total consideration of $40.9 million.

As previously announced, we plan to return at least 60% of second half 2023 free cash flow to shareholders through share repurchases and dividends, which is expected to result in over 70% of full year 2023 free cash flow returned. In conjunction with this plan, the Board of Directors approved a fourth quarter dividend of $0.06 per share to be paid in December 2023. The Company expects to continue to return significant free cash flow to shareholders in 2024 and anticipates its return of capital will equal approximately 70% of free cash flow. Based on current market conditions, the Company expects to continue to prioritize share repurchases for the majority of its return of capital plan. Remaining free cash flow not allocated to return of capital is expected to be directed to reinforcing the balance sheet.

At September 30, 2023, 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.sedarplus.ca.

[1] This financial measure is a supplementary financial measure. See "Non-GAAP Measures – Supplementary Financial Measures" section in this MD&A.

The following table lists our financial covenants at September 30, 2023:

Covenant Description		September 30, 2023
Bank Credit Facilities:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	0.2x
Total debt to adjusted EBITDA	4.0x	0.2x
Total debt to capitalization	55%	12%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA[(1)]	3.0x - 3.5x	0.2x
Senior debt to consolidated present value of total proved reserves[(2)]	60%	6%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	65.6x

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, 2023 was $282.5 million and $1,225.0 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)	2023	2022	2023	2022
Dividends	$ 12.6	$ 11.5	$ 36.4	$ 29.4
Per weighted average share (Basic)	$ 0.060	$ 0.050	$ 0.170	$ 0.126

During the three and nine months ended September 30, 2023, we declared total dividends of $12.6 million, or $0.06 per share, and $36.4 million, or $0.17 per share, respectively, compared to $11.5 million, or $0.05 per share, and $29.4 million, or $0.126 per share for the same periods in 2022. The total amount of dividends paid to shareholders has increased compared to the same period in 2022 due to the increased sustainability of the business and as a result of our current return of capital plan.

Subsequent to September 30, 2023, the Board of Directors approved a fourth quarter dividend of $0.06 per share to be paid in December 2023. We expect to fund the dividend through the free cash flow generated by the business.

Shareholders' Capital

	Nine months ended September 30,	
	2023	2022
Share capital ($ millions)	$ 2,745.6	$ 2,926.2
Common shares outstanding (thousands)	207,985	226,966
Weighted average shares outstanding – basic (thousands)	213,621	237,835
Weighted average shares outstanding – diluted (thousands)	220,093	245,403

For the nine months ended September 30, 2023, a total of 2.4 million units vested pursuant to our treasury-settled LTI plans, including the impact of performance multipliers (2022 – 2.2 million). In total, 1.3 million shares were issued from treasury and $7.3 million was transferred from paid-in capital to share capital (2022 – 1.2 million shares; $8.0 million). We elected to cash-settle the remaining units related to the required tax withholdings for the total amount of $16.5 million (2022 – $11.6 million).

On August 4, 2023, we filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces and territories of Canada and a Registration Statement with the U.S. Securities and Exchange Commission. The Shelf Prospectus allows us to offer and issue common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains valid.

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), or 21.0 million common shares, during a 12-month period. The Company completed its previous NCIB in July 2023.

During the nine months ended September 30, 2023, 10.6 million common shares were repurchased and cancelled under the NCIB at an average price of $15.50 per share, for total consideration of $164.4 million. Of the amount paid, $99.0 million was charged to share capital and $65.4 million was added to accumulated deficit.

During the nine months ended September 30, 2022, 18.1 million 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 added to accumulated deficit.

Subsequent to September 30, 2023 and up to November 1, 2023, we repurchased 2.5 million common shares under the NCIB at an average price of $16.65 per share, for total consideration of $40.9 million. At November 1, 2023, 15.8 million common shares remain available for repurchase under the current NCIB.

At November 1, 2023, we had 205,529,455 common shares outstanding. In addition, an aggregate of 7,991,418 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.

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
2023				
Third Quarter	$ 461.8	$ 127.7	$ 0.61	$ 0.59
Second Quarter	350.9	74.2	0.35	0.34
First Quarter	413.2	137.5	0.63	0.62
Total 2023	$ 1,226.0	$ 339.4	$ 1.59	$ 1.54
2022				
Fourth Quarter	$ 548.7	$ 330.7	$ 1.49	$ 1.43
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	$ 2,353.4	$ 914.3	$ 3.91	$ 3.77
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

Crude oil and natural gas sales increased to $461.8 million during the third quarter of 2023, compared to $350.9 million during the second quarter of 2023. We reported net income of $127.7 million during the third quarter of 2023 compared to net income of $74.2 million during the second quarter of 2023. The increase in crude oil and natural gas sales and net income was primarily due to higher commodity prices and higher crude oil and natural gas liquids production in the third quarter of 2023.

Crude oil and natural gas sales increased in 2022, compared to 2021, due to higher production and improved realized pricing. Net income increased in 2022, compared to 2021, due to higher production and commodity prices as well as the gain on the Canadian asset divestments recorded in the fourth quarter of 2022.

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, 2022.

2023 GUIDANCE[1]

Summary of 2023 Annual Expectations	Target
Capital spending ($ millions)	$520 to $540 (from $510 to $550)
Average annual production (BOE/day)	98,000 - 99,000 (from 94,500 - 98,500)
Average annual crude oil and natural gas liquids production (bbls/day)	60,500 - 61,500 (from 58,500 - 61,500)
Fourth quarter average production (BOE/day)	95,000 - 99,000
Fourth quarter average crude oil and natural gas liquids production (bbls/day)	60,500 - 64,500
Average production tax rate (% of gross sales, before transportation)	8%
Operating expenses (per BOE)	$10.75 - $11.00 (from $10.75 - $11.50)
Transportation costs (per BOE)	$4.05 (from $4.20)
Cash G&A expenses (per BOE)	$1.35
Current tax expense (% of adjusted funds flow before tax)	3% - 4%

Differential/Basis Outlook[2]	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	($0.25)/bbl (from $0.00/bbl)
Average Marcellus natural gas differential (compared to last day NYMEX natural gas)	($0.85)/Mcf (from ($0.75)/Mcf)

(1) This constitutes forward-looking information. Refer to “Forward-Looking Information and Statements” section in this MD&A.
(2) 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: (a) indicated the composition of the measure; (b) identified the most directly comparable GAAP financial measure and provided comparative detail where appropriate; (c) indicated the reconciliation of the measure to the most directly comparable GAAP financial measure to the extent one exists; and (d) 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).

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2023	2022	2023	2022
Net income/(loss)	**$ 127.7**	**$ 305.9**	**$ 339.4**	**$ 583.6**
Unrealized derivative instrument, foreign exchange and marketable securities (gain)/loss	15.6	(128.5)	32.0	(88.5)
Other expense/(income) related to investing activities	(1.4)	—	(1.4)	13.1
Tax effect	(4.7)	30.5	(7.7)	17.8
Adjusted net income/(loss)	**$ 137.2**	**$ 207.9**	**$ 362.3**	**$ 526.0**

“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)	2023	2022	2023	2022
Cash flow from/(used in) operating activities	$ 212.2	$ 409.9	$ 640.2	$ 856.8
Asset retirement obligation settlements	2.5	1.6	11.3	12.7
Changes in non-cash operating working capital	49.0	(55.9)	69.1	45.4
Adjusted funds flow	**$ 263.7**	**$ 355.6**	**$ 720.6**	**$ 914.9**
Capital spending	(121.4)	(114.5)	(440.9)	(346.4)
Free cash flow	**$ 142.3**	**$ 241.1**	**$ 279.7**	**$ 568.5**

“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)	2023	2022	2023	2022
Crude oil and natural gas sales	$ 461.8	$ 663.5	$ 1,226.0	$ 1,804.7
Less:				
Operating expenses	(96.6)	(103.8)	(278.5)	(270.5)
Transportation expenses	(36.7)	(41.3)	(108.9)	(114.9)
Production taxes	(40.0)	(48.2)	(98.8)	(127.4)
Netback before impact of commodity derivative contracts	**$ 288.5**	**$ 470.2**	**$ 739.8**	**$ 1,291.9**
Net realized gain/(loss) on derivative instruments	5.3	(88.5)	53.8	(299.8)
Netback after impact of commodity derivative contracts	**$ 293.8**	**$ 381.7**	**$ 793.6**	**$ 992.1**

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

We are required to comply with National Instrument 52-109 - Certification of Disclosure in Issuers' Annual and Interim Filings. This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to Enerplus' internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended September 30, 2023.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our Annual Information Form, is available under our profile on the SEDAR+ website at www.sedarplus.ca, on the EDGAR website at www.sec.gov and at www.enerplus.com.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: expectations regarding Enerplus' business, operations and financial condition in 2023 and beyond; 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; expected production volumes in 2023, including the production mix, and 2023 production guidance; 2023 capital spending guidance; expectations regarding free cash flow generation and long-term capital spending reinvestment rates; expected operating strategy in 2023; 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 2023; 2023 Bakken and Marcellus differential guidance; capital spending guidance; expectations regarding realized oil and natural gas prices; expected operating, transportation and cash G&A expenses and production taxes and 2023 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 2023 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; 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; 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; our ability to comply with our debt covenants; our ability to meet the targets associated with the Bank Credit Facilities; 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 2023 guidance described in this MD&A is based on rest of year commodity prices of: a WTI price of $80.00/bbl, a NYMEX price of $3.00/Mcf, 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 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, 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, as well as changes to the market conditions, that could impact our planned share repurchases and dividend levels, including the timing and sources of financing thereof; 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, 2022), which are available at www.sedarplus.ca, 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.