second quarter report

six months ended June 30, 2022

enerPLUS

SELECTED FINANCIAL RESULTS	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Financial (US$, thousands, except ratios)				
Net Income/(Loss)	$ 244,406	$ (50,933)	$ 277,649	$ (40,584)
Adjusted Net Income[1]	172,251	54,666	318,079	98,537
Cash Flow from Operating Activities	250,860	110,466	446,852	139,128
Adjusted Funds Flow	297,393	149,971	559,288	250,825
Dividends to Shareholders - Declared	9,940	9,088	17,858	14,722
Net Debt	545,983	913,729	545,983	913,729
Capital Spending	132,884	105,859	231,898	157,676
Property and Land Acquisitions	1,469	332,185	3,410	829,325
Property Divestments	8,591	(12)	15,172	3,998
Net Debt to Adjusted Funds Flow Ratio	0.5x	2.4x	0.5x	2.4x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ 1.01	$ (0.20)	$ 1.15	$ (0.16)
Net Income/(Loss) - Diluted	0.99	(0.20)	1.12	(0.16)
Weighted Average Number of Shares Outstanding (000's) - Basic	239,277	256,750	241,022	250,443
Weighted Average Number of Shares Outstanding (000's) - Diluted	247,216	256,750	248,957	250,443
Selected Financial Results per BOE[2][3]				
Crude Oil & Natural Gas Sales[4]	$ 73.31	$ 39.53	$ 67.67	$ 37.28
Commodity Derivative Instruments	(16.13)	(3.68)	(12.53)	(3.08)
Operating Expenses	(9.74)	(8.55)	(9.88)	(8.18)
Transportation Costs	(4.41)	(3.50)	(4.36)	(3.68)
Production Taxes	(5.11)	(2.95)	(4.70)	(2.57)
General and Administrative Expenses	(1.10)	(1.04)	(1.22)	(1.28)
Cash Share-Based Compensation	(0.04)	(0.23)	(0.14)	(0.27)
Interest, Foreign Exchange and Other Expenses	(0.67)	(1.40)	(0.67)	(1.34)
Current Income Tax Recovery/(Expense)	(1.40)	(0.40)	(1.01)	(0.23)
Adjusted Funds Flow	$ 34.71	$ 17.78	$ 33.16	$ 16.65

SELECTED OPERATING RESULTS	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Average Daily Production[3]				
Crude Oil (bbls/day)	48,213	49,649	47,925	41,923
Natural Gas Liquids (bbls/day)	8,653	7,941	8,516	6,613
Natural Gas (Mcf/day)	223,653	210,572	220,400	208,273
Total (BOE/day)	94,142	92,685	93,174	83,248
% Crude Oil and Natural Gas Liquids	60%	62%	61%	58%
Average Selling Price[3][4]				
Crude Oil (per bbl)	$ 108.77	$ 62.50	$ 100.46	$ 58.75
Natural Gas Liquids (per bbl)	33.31	18.47	35.49	22.46
Natural Gas (per Mcf)	6.11	1.96	5.38	2.35
Net Wells Drilled	16.5	5.0	31.7	5.0

(1) This financial measure is a non-GAAP financial measure and may not be directly comparable to similar measures presented by other entities. See “Non-GAAP Measures” section in this MD&A.
(2) Non-cash amounts have been excluded.
(3) Based on Net production volumes. See “Basis of Presentation” section in the following MD&A.
(4) Before transportation costs and commodity derivative instruments.

Average Benchmark Pricing	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
WTI crude oil ($/bbl)	$ 108.41	$ 66.07	$ 101.35	$ 61.96
Brent (ICE) crude oil ($/bbl)	111.78	69.02	104.58	65.06
NYMEX natural gas – last day ($/Mcf)	7.17	2.83	6.06	2.76
CDN/US average exchange rate	0.78	0.81	0.79	0.80

Share Trading Summary For the three months ended June 30, 2022	U.S.(1) - ERF (US$)	CDN(2) - ERF (CDN$)
High	$ 18.58	$ 23.29
Low	$ 11.25	$ 14.68
Close	$ 13.23	$ 17.01

(1) TSX and other Canadian trading data combined.
(2) NYSE and other U.S. trading data combined.

2022 Dividends Declared per Share	US$	CDN$(1)
First Quarter Total	$ 0.033	$ 0.042
Second Quarter Total	$ 0.043	$ 0.056
Total	$ 0.076	$ 0.098

(1) CDN$ dividends converted at the relevant foreign exchange rate on the payment date.

HIGHLIGHTS

- Adjusted funds flow was $297.4 million in the second quarter, which exceeded capital spending of $132.9 million, generating free cash flow[(1)] of $164.5 million
- Increased 2022 free cash flow[(1)] estimate to $800 million based on rest of year prices of $90 WTI and $6.50 NYMEX
- Normal course issuer bid ("NCIB") was fully executed for 10% of the public float having repurchased 25.6 million shares between August 2021 and July 2022 at an average price of $11.14 per share, for total consideration of $284.8 million.
- Increased return of capital framework to at least 60% of free cash flow commencing in the second half of 2022 and continuing through 2023
- Increased minimum 2022 return of capital commitment to $425 million, from $350 million previously
- Increased quarterly dividend by 16% to $0.05 per share
- Production guidance for 2022 increased to 97,500 – 101,500 BOE per day (from 96,000 – 101,000 BOE per day) due to continued strong operational performance with no change to capital spending guidance and despite the recently announced sale of assets in Canada expected to impact 2022 production by approximately 850 BOE per day
- Robust volume growth anticipated in the second half of 2022: approximately 15% liquids production growth expected in the third quarter compared to the second quarter

[(1)] This is a non-GAAP financial measure. Refer to "Non-GAAP and Other Financial Measures" section for more information.

"Enerplus' second quarter results and updated 2022 outlook reflect our company's strong operating momentum and disciplined approach to capital allocation," said Ian C. Dundas, President and CEO. "Our annual production guidance has continued to move higher driven by well outperformance and efficient execution, while our capital spending plans remain unchanged."

Dundas continued, "Enerplus is in a solid financial position with a compelling free cash flow profile. As a result, we are increasing our cash returns to shareholders to at least 60% of free cash flow in the second half of this year, with a minimum commitment of returning $425 million in 2022 through dividends and share repurchases. We are also committing to returning at least 60% of 2023 free cash flow to shareholders."

SECOND QUARTER SUMMARY

Production in the second quarter of 2022 was 94,142 BOE per day, an increase of 2% compared to the prior quarter and the same period a year ago. Crude oil and natural gas liquids production in the second quarter of 2022 was 56,866 barrels per day, an increase of 2% compared to the prior quarter, and 1% lower than the same period a year ago. As previously noted, second quarter volumes were impacted by severe winter weather in North Dakota during April 2022, however, through strong operational performance and the continued optimization of the Company's development plan, Enerplus has been able to more than offset the impact from the storm to its annual production forecast. Third quarter liquids production is expected to be approximately 15% higher than the second quarter.

Enerplus reported second quarter 2022 net income of $244.4 million, or $0.99 per share (diluted), compared to a net loss of $50.9 million, or $0.20 per share (diluted), in the same period in 2021. Adjusted net income[(1)] for the second quarter of 2022 was $172.3 million, or $0.70 per share (diluted), compared to $54.7 million, or $0.21 per share (diluted), during the same period in 2021. Net income and adjusted net income were higher compared to the prior year period primarily due to higher realized commodity prices during the second quarter of 2022.

Enerplus' second quarter 2022 realized Bakken oil price differential was $0.85 per barrel above WTI, compared to $2.81 per barrel below WTI in the second quarter of 2021. Bakken crude oil price differentials turned positive to WTI due to increasing demand, excess pipeline capacity in the region and strong prices for crude oil delivered to the U.S. Gulf Coast. Given the constructive outlook for Bakken crude oil prices and strong realizations year to date, Enerplus expects its 2022 realized average Bakken crude oil differential to be $1.00 per barrel above WTI, compared to a price at par with WTI, previously.

The Company's realized Marcellus natural gas price differential was $0.59 per Mcf below NYMEX during the second quarter of 2022, compared to $0.89 per Mcf below NYMEX in the second quarter of 2021. Realized Marcellus differentials are expected to widen for the remainder of the year due to the seasonal impact on natural gas prices in the region. Enerplus' full-year 2022 Marcellus differential guidance is unchanged at $0.75 per Mcf below NYMEX.

In the second quarter of 2022, Enerplus' operating costs were $9.74 per BOE, compared to $8.56 per BOE during the second quarter of 2021. The increase in per unit operating expenses was primarily due to contracts with price escalators linked to WTI and the Consumer Price Index.

Capital spending totaled $132.9 million in the second quarter of 2022. In addition, Enerplus paid $9.9 million in dividends in the quarter and repurchased 7.1 million shares at an average price of $13.13 per share, for total consideration of $92.9 million. During July 2022, Enerplus repurchased the remaining 2.5 million shares under its 10% NCIB authorization at an average price of $12.81 per share, for total consideration of $31.5 million.

Enerplus ended the second quarter of 2022 with total debt of $571.4 million and cash of $25.4 million.

(1) This is a non-GAAP financial measure. Refer to "Non-GAAP and Other Financial Measures" section for more information.

ASSET HIGHLIGHTS

North Dakota production averaged 58,626 BOE per day during the second quarter of 2022, an increase of 4% compared to the same period a year ago and 2% higher compared to the previous quarter. Severe winter weather temporarily impacted Enerplus' North Dakota operations during April 2022, however, strong well performance is expected to drive significant volume growth into the third quarter. Enerplus drilled 13 gross operated wells (88% working interest) during the second quarter and brought 24 operated wells (88% working interest) on production.

Marcellus production averaged 168 MMcf per day during the second quarter of 2022, an increase of 9% compared to the same period in 2021 and 3% higher than the prior quarter.

INCREASING RETURN OF CAPITAL TO SHAREHOLDERS

Based on strong operating and financial performance through the first half of 2022 and to date, a robust free cash flow outlook, and the recently announced divestment of assets in Canada, Enerplus is increasing its return of capital to shareholders. Under its updated framework, the Company plans to return at least 60% of its free cash flow to shareholders (from 50% previously) commencing in the second half of 2022 and continuing through 2023. Enerplus is also increasing its minimum 2022 return of capital commitment to $425 million, from $350 million previously. Year to date through July, Enerplus has returned $179 million through dividends and share repurchases, leaving a minimum remaining return of $246 million by the end of 2022.

In connection with this plan, Enerplus' board of directors has approved the renewal of its NCIB for another 10% of the public float in August 2022, subject to Toronto Stock Exchange approval, and a 16% increase to the quarterly dividend to $0.05 per share payable on September 15, 2022 to shareholders of record on August 31, 2022.

Enerplus plans to continue to prioritize share repurchases for the majority of its return of capital to shareholders due to its assessment that its intrinsic value, based on its mid-cycle commodity price view, is not adequately reflected in its current trading value. If this view changes such that Enerplus believes share repurchases no longer represent an attractive capital allocation opportunity, the Company will distribute the capital to shareholders through dividends to ensure it meets its shareholder returns commitment.

Remaining free cash flow not allocated to shareholder returns is expected to be directed to reinforcing the balance sheet.

2022 GUIDANCE UPDATE

Updates to Enerplus' 2022 guidance are provided in the tables below.

Enerplus is increasing its production guidance to 97,500 to 101,500 BOE per day, from the prior guidance of 96,000 to 101,000 BOE per day. Liquids production guidance has been updated to 59,500 to 62,500 barrels per day, from 58,500 to 62,500 barrels per day previously. The increase reflects strong well performance and the continued optimization of Enerplus' development plan. This update represents an increase of 1,000 BOE per day based on the guidance midpoint despite the expected loss of production associated with the recently announced sale of assets in Canada which is anticipated to close at the end of the third quarter and impact 2022 production by approximately 850 BOE per day.

There are no changes to capital spending guidance.

2022 Guidance Summary

	Updated Guidance	Previous Guidance
Capital spending	$400 – 440 million (No change)	$400 – 440 million
Average total production	97,500 – 101,500 BOE/day	96,000 – 101,000 BOE/day
Average liquids production	59,500 – 62,500 bbls/day	58,500 – 62,500 bbls/day
Average production tax rate (% of net sales, before transportation)	7% (No change)	7%
Operating expense	$10.00/BOE	$9.75 – 10.50/BOE
Transportation expense	$4.25/BOE	$4.15/BOE
Cash G&A expense	$1.20/BOE	$1.25/BOE
Current tax expense	(2-3% of adjusted funds flow before tax)	$20 - 30 million (2-3% of adjusted funds flow before tax)

2022 Differential/Basis Outlook[1]

	Updated Guidance	Previous Guidance
U.S. Bakken crude oil differential (compared to WTI crude oil)	$+1.00/bbl	$0/bbl
Marcellus natural gas sales differential (compared to NYMEX natural gas)	$(0.75)/Mcf (No change)	$(0.75)/Mcf

(1) Excluding transportation costs.

UPDATED FIVE-YEAR OUTLOOK

Enerplus has updated its five-year outlook to reflect the higher current commodity price and inflationary environment and to exclude its Canadian assets due to the previously announced and ongoing divestment process. Enerplus' previous five-year outlook was based on a commodity price environment of $70 per barrel WTI and $3.00 per Mcf NYMEX. Enerplus is increasing its commodity price assumptions to $80 per barrel WTI and $4.00 per Mcf NYMEX[1] and is updating its projected annual capital spending to approximately $500 million (2023-2026) to account for higher anticipated costs due to inflation. The Company's outlook continues to be underpinned by a focus on operating with low financial leverage, delivering strong and sustainable free cash flow growth, and returning capital to shareholders.

Enerplus estimates cumulative free cash flow[2] of approximately $3 billion between 2022 and 2026 and an average reinvestment rate of less than 50% over the period. Enerplus projects 3% to 5% annual liquids production growth between 2023 and 2026 on a divestment adjusted basis. 2022 annual production growth is projected to be approximately 8% which is partially impacted by the timing of the Company’s 2021 acquisitions.

(1) 2022 is based on prices of $90/bbl WTI and $6.50/Mcf NYMEX for the remainder of 2022.

(2) This is a non-GAAP financial measure. Refer to "Non-GAAP and Other Financial Measures" section for more information.

Q2 2022 CONFERENCE CALL DETAILS

A conference call hosted by Ian C. Dundas, President and CEO will be held at 9:00 AM MT (11:00 AM ET) on August 5, 2022, to discuss these results. Details of the conference call are as follows:

Date:	Friday, August 5, 2022
Time:	9:00 AM MT (11:00 AM ET)
Dial-In:	587-880-2171 (Alberta) 1-888-390-0546 (Toll Free)
Conference ID:	73519318
Audiocast:	https://produceredition.webcasts.com/starthere.jsp?ei=1557604&tp_key=1b2aa32a82

To ensure timely participation in the conference call, callers are encouraged to join 15 minutes prior to the start time to register for the event. A telephone replay will be available for 30 days following the conference call and can be accessed at the following numbers:

Replay Dial-In:	1-888-390-0541 (Toll Free)
Replay Passcode:	519318 #

PRICE RISK MANAGEMENT

The following is a summary of Enerplus' financial commodity hedging contracts 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 outstanding hedges is $1.50/bbl from July 1, 2022 - December 31, 2022 and $1.25/bbl from January 1, 2023 – June 30, 2023.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Upon closing of the acquisition (the "Bruin Acquisition") of Bruin E&P Holdco, LLC ("Bruin"), Bruin's outstanding crude oil contracts were recorded at a fair value liability of $76.4 million. At June 30, 2022, the balance was a liability of $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. See Note 16 to the Interim Financial Statements for further details.

SECOND QUARTER 2022 PRODUCTION AND OPERATIONAL SUMMARY TABLES

Summary of Average Daily Production(1)

	Three months ended June 30, 2022					Six months ended June 30, 2022				
	Williston Basin	Marcellus	Canadian Water-floods	Other(2)	Total	Williston Basin	Marcellus	Canadian Water-floods	Other(2)	Total
Tight oil (bbl/d)	42,447	—	—	798	**43,245**	42,003	—	—	836	**42,839**
Light & medium oil (bbl/d)	—	—	2,054	29	**2,082**	—	—	2,101	26	**2,127**
Heavy oil (bbl/d)	—	—	2,872	14	**2,886**	—	—	2,949	10	**2,959**
Total crude oil (bbl/d)	**42,447**	—	**4,926**	**841**	**48,213**	**42,003**	—	**5,051**	**872**	**47,925**
Natural gas liquids (bbl/d)	**8,231**	—	**87**	**336**	**8,653**	**8,106**	—	**87**	**323**	**8,516**
Shale gas (Mcf/d)	47,689	167,631	—	1,014	**216,334**	47,276	164,900	—	968	**213,144**
Conventional natural gas (Mcf/d)	—	—	1,459	5,860	**7,319**	—	—	1,420	5,836	**7,256**
Total natural gas (Mcf/d)	**47,689**	**167,631**	**1,459**	**6,874**	**223,653**	**47,276**	**164,900**	**1,420**	**6,804**	**220,400**
Total production (BOE/d)	**58,626**	**27,938**	**5,255**	**2,322**	**94,142**	**57,988**	**27,483**	**5,375**	**2,329**	**93,174**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and other properties in Canada.

Summary of Wells Drilled[1]

	Three months ended June 30, 2022				Six months ended June 30, 2022			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	13	11.5	17	3.2	27	23.5	29	4.7
Marcellus	—	—	21	1.7	—	—	38	3.1
Canadian Waterfloods	—	—	—	—	—	—	—	—
Other[2]	—	—	4	0.1	—	—	15	0.4
Total	**13**	**11.5**	**42**	**5.0**	**27**	**23.5**	**82**	**8.2**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and other properties in Canada.

Summary of Wells Brought On-Stream[1]

	Three months ended June 30, 2022				Six months ended June 30, 2022			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	24	21.0	5	0.4	26	23.0	5	0.4
Marcellus	—	—	22	1.4	—	—	47	2.9
Canadian Waterfloods	—	—	—	—	—	—	—	—
Other[2]	—	—	—	—	—	—	—	—
Total	**24**	**21.0**	**27**	**1.8**	**26**	**23.0**	**52**	**3.3**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and other properties in Canada.

Currency and Accounting Principles

All amounts in this news release are stated in U.S. dollars unless otherwise specified. All financial information in this news release has been prepared and presented in accordance with U.S. GAAP, except as noted below under “Non-GAAP and Other Financial Measures”.

Barrels of Oil Equivalent

This news release contains references to "BOE" (barrels of oil equivalent), “MBOE” (one thousand barrels of oil equivalent), and “MMBOE” (one million barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

Basis of Presentation

All production volumes presented in this news release are reported on a "net" basis (the Company's working interest share after deduction of royalty obligations, plus the Company's royalty interests), unless expressly indicated that it is being presented on a "gross" basis. Previously, the Company presented production volumes on a "company interest" basis, which was calculated as its working interest share before deduction of royalties plus the Company's royalty interests. With these changes, production volumes presented by the Company on a "net" basis are expected to be lower than those presented historically.

All references to "liquids" in this news release include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and NGLs on a combined basis. All references to "natural gas" in this news release include conventional natural gas and shale gas on a combined basis.

Readers are urged to review the 2021 annual MD&A and financial statements filed on SEDAR and as part of our Form 40-F on EDGAR concurrently with this news release for more complete disclosure on our operations.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release 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 news release contains forward-looking information pertaining to the following: the recently announced sale of certain assets in Canada and the expected impact thereof on Enerplus’ operations, financial results and five year outlook; updated 2022 production guidance; capital spending guidance and expected capital spending levels in 2022 and future years; expectations regarding free cash flow generation and reinvestment rates; expected operating strategy in 2022 and expectations regarding our drilling program and well costs; 2022 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas 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 tax expenses and updated 2022 guidance with respect thereto; expectations regarding return of cash to our shareholders, and timing thereof; expectations regarding increases to dividends and timing thereof; expectations regarding funding of return of cash and dividends from free cash flow; expectations regarding renewal of our normal course issuer bid, including timing and size thereof; and our five year outlook.

The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that Enerplus will realize the expected impact of the recently announced sale of certain assets in Canada; the continued operation of the Dakota Access Pipeline; 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 expected returns of cash and increased dividends from free cash flow as expected and discussed in this news release and the ability to execute our share repurchase program as currently expected and in compliance with applicable Canadian and US rules; our ability to comply with our debt covenants; the availability of third party services; expected transportation expenses; the extent of our liabilities; and the availability of technology and process to achieve environmental targets. In addition, our 2022 guidance described in this news release is based on rest of year commodity prices of: $90.00/bbl WTI and $6.50/Mcf 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 news release is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued instability, or further deterioration, in global economic and market environment, including from COVID-19, 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 the Dakota Access Pipeline; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit 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; failure to complete the recently announced sale of certain assets in Canada; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our first quarter 2022 MD&A, our annual information form for the year ended December 31, 2021, our 2021 annual MD&A and Form 40-F as 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 news release speaks only as of the date of this news release. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.

NON-GAAP AND OTHER FINANCIAL MEASURES

Non-GAAP Financial Measures

This news release 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)" and "**Adjusted net income/(loss) per share (diluted)**" are used by Enerplus and are 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 ended June 30, 2022 and 2021. Adjusted net income per share is calculated using adjusted net income, as reconciled below, divided by the number of common shares outstanding on a diluted basis during the applicable period as determined in accordance with U.S. GAAP. The calculation follows:

	Three months ended June 30,	
($ millions)	2022	2021
Net income/(loss)	**$ 244.4**	**$ (50.9)**
Unrealized commodity derivative instrument (gain)/loss	(91.3)	130.3
Asset impairment	—	—
Other expense related to investing activities	—	—
Unrealized foreign exchange (gain)/loss	(3.3)	6.8
Tax effect on above items	22.5	(31.5)
Adjusted net income/(loss)	**$ 172.3**	**$ 54.7**
Adjusted net income/(loss) per share (diluted)	**$ 0.70**	**$ 0.21**

"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,	
($ millions)	2022	2021
Cash flow from/(used in) operating activities	$ 250.9	$ 110.5
Asset retirement obligation settlements	2.3	1.2
Changes in non-cash operating working capital	44.2	38.3
Adjusted funds flow	**$ 297.4**	**$ 150.0**
Capital spending	(132.9)	(105.9)
Free cash flow	**$ 164.5**	**$ 44.1**

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. 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 as compared to adjusted funds flow (as a percentage).

Electronic copies of Enerplus’ second quarter 2022 and annual 2021 Financial Statements and associated MD&As, along with other public information including investor presentations, are or will be available on the Company’s website at www.enerplus.com. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

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.

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.

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

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:

	Six months ended June 30,						
Pricing (average for the period)	**2022**	**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)	**Three months ended June 30,**		**Six months ended June 30,**	
($ millions)	**2022**	**2021**	**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)

	Three months ended June 30,		**Six months ended June 30,**	
(Per BOE)	**2022**	**2021**	**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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2022	2021	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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2022	2021	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.

	Three months ended June 30, 2021		
Netbacks by Property Type	**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.

Condensed Consolidated Balance Sheets

(US$ thousands) unaudited	Note	June 30, 2022	December 31, 2021
Assets			
Current assets			
Cash and cash equivalents		$ 25,406	$ 61,348
Accounts receivable	3	387,811	227,988
Other current assets	6	8,480	10,956
Derivative financial assets	16	3,547	5,668
		425,244	305,960
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	4, 5	1,380,251	1,253,505
Other capital assets	4	12,152	13,887
Property, plant and equipment		1,392,403	1,267,392
Other long-term assets	6	7,440	9,756
Right-of-use assets	10	22,772	26,118
Derivative financial assets	16	2,298	—
Deferred income tax asset	14	294,854	380,858
Total Assets		$ 2,145,011	$ 1,990,084
Liabilities			
Current liabilities			
Accounts payable	7	$ 463,230	$ 367,008
Income tax payable		11,600	—
Current portion of long-term debt	8	80,600	100,600
Derivative financial liabilities	16	171,904	143,200
Current portion of lease liabilities	10	8,327	10,618
		735,661	621,426
Long-term debt	8	490,789	601,171
Asset retirement obligation	9	162,965	132,814
Derivative financial liabilities	16	8,054	7,098
Lease liabilities	10	17,017	18,265
		678,825	759,348
Total Liabilities		1,414,486	1,380,774
Shareholders’ Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: June 30, 2022 – 235 million shares			
December 31, 2021 – 244 million shares	15	3,001,604	3,094,061
Paid-in capital		41,843	50,881
Accumulated deficit		(2,008,253)	(2,238,325)
Accumulated other comprehensive loss		(304,669)	(297,307)
		730,525	609,310
Total Liabilities & Shareholders' Equity		$ 2,145,011	$ 1,990,084

Subsequent Events	15, 18		

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Income/(Loss) and Comprehensive Income/(Loss)

(US$ thousands, except per share amounts) unaudited	Note	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Revenues					
Crude oil and natural gas sales	11	$ 628,017	$ 333,422	$ 1,141,169	$ 561,812
Commodity derivative instruments gain/(loss)	16	(47,553)	(161,822)	(254,363)	(218,085)
		580,464	171,600	886,806	343,727
Expenses					
Operating		83,366	72,159	166,610	123,321
Transportation		37,830	29,475	73,637	55,402
Production taxes		43,827	24,923	79,182	38,768
General and administrative	12	14,687	10,134	32,268	22,975
Depletion, depreciation and accretion		70,090	76,444	136,781	113,142
Asset impairment	5	—	—	—	3,420
Interest		6,098	7,777	12,153	13,410
Foreign exchange (gain)/loss	13	(3,232)	7,778	(2,345)	7,754
Transaction costs and other expense/(income)	9	(309)	(563)	12,388	3,056
		252,357	228,127	510,674	381,248
Income/(Loss) before taxes		328,107	(56,527)	376,132	(37,521)
Current income tax expense	14	12,000	3,415	17,000	3,415
Deferred income tax expense/(recovery)	14	71,701	(9,009)	81,483	(352)
Net Income/(Loss)		$ 244,406	$ (50,933)	$ 277,649	$ (40,584)
Other Comprehensive Income/(Loss)					
Unrealized gain/(loss) on foreign currency translation		1,977	88	1,357	(719)
Foreign exchange gain/(loss) on net investment hedge, net of tax	16	(14,094)	10,178	(8,719)	15,892
Total Comprehensive Income/(Loss)		$ 232,289	$ (40,667)	$ 270,287	$ (25,411)
Net Income/(Loss) per share					
Basic	15	$ 1.01	$ (0.20)	$ 1.15	$ (0.16)
Diluted	15	$ 0.99	$ (0.20)	$ 1.12	$ (0.16)

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Changes in Shareholders' Equity

(US$ thousands) unaudited	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Share Capital				
Balance, beginning of period	$ 3,070,678	$ 3,222,747	$ 3,094,061	$ 3,113,829
Issue of shares (net of tax effected issue costs)	—	—	—	99,516
Purchase of common shares under Normal Course Issuer Bid	(69,074)	—	(100,416)	—
Share-based compensation – treasury settled	—	—	7,959	9,402
Balance, end of period	$ 3,001,604	$ 3,222,747	$ 3,001,604	$ 3,222,747
Paid-in Capital				
Balance, beginning of period	$ 36,110	$ 38,083	$ 50,881	$ 49,382
Share-based compensation – tax withholdings settled in cash	—	—	(11,567)	(3,551)
Share-based compensation – treasury settled	—	—	(7,959)	(9,402)
Share-based compensation – non-cash	5,733	(27)	10,488	1,627
Balance, end of period	$ 41,843	$ 38,056	$ 41,843	$ 38,056
Accumulated Deficit				
Balance, beginning of period	$ (2,218,865)	$ (2,443,020)	$ (2,238,325)	$ (2,447,735)
Purchase of common shares under Normal Course Issuer Bid	(23,854)	—	(29,719)	—
Net income/(loss)	244,406	(50,933)	277,649	(40,584)
Dividends declared[1]	(9,940)	(9,088)	(17,858)	(14,722)
Balance, end of period	$ (2,008,253)	$ (2,503,041)	$ (2,008,253)	$ (2,503,041)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of period	$ (292,552)	$ (289,604)	$ (297,307)	$ (294,511)
Unrealized gain/(loss) on foreign currency translation	1,977	88	1,357	(719)
Foreign exchange gain/(loss) on net investment hedge, net of tax	(14,094)	10,178	(8,719)	15,892
Balance, end of period	$ (304,669)	$ (279,338)	$ (304,669)	$ (279,338)
Total Shareholders' Equity	$ 730,525	$ 478,424	$ 730,525	$ 478,424

(1) For the three and six months ended June 30, 2022, dividends declared were $0.043 per share and $0.076 per share, respectively (2021 – $0.035 per share and $0.059 per share, respectively).

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Condensed Consolidated Statements of Cash Flows

(US$ thousands) unaudited	Note	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Operating Activities					
Net income/(loss)		$ 244,406	$ (50,933)	$ 277,649	$ (40,584)
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		70,090	76,444	136,781	113,142
Asset impairment	5	—	—	—	3,420
Changes in fair value of derivative instruments	16	(91,275)	130,280	42,057	170,638
Deferred income tax expense/(recovery)	14	71,701	(9,009)	81,483	(352)
Foreign exchange (gain)/loss on debt and working capital	13	(3,292)	6,848	(2,121)	7,005
Share-based compensation and general and administrative	12,15	5,634	(19)	10,294	783
Other expense	9	(97)	(1,917)	12,556	(1,917)
Amortization of debt issuance costs	8	351	252	704	309
Translation of U.S. dollar cash held in parent company	13	(125)	(1,975)	(115)	(1,619)
Asset retirement obligation settlements	9	(2,349)	(1,155)	(11,144)	(6,780)
Changes in non-cash operating working capital	17	(44,184)	(38,350)	(101,292)	(104,917)
Cash flow from/(used in) operating activities		250,860	110,466	446,852	139,128
Financing Activities					
Drawings from/(repayment of) bank credit facilities	8	48,709	275,000	(55,700)	675,000
Repayment of senior notes	9	(79,600)	(81,600)	(79,600)	(81,600)
Debt issuance costs	8	—	(1,787)	—	(4,621)
Proceeds from the issuance of shares	15	—	—	—	98,339
Purchase of common shares under Normal Course Issuer Bid	15	(92,928)	—	(130,135)	—
Share-based compensation – tax withholdings settled in cash	15	—	—	(11,567)	(3,551)
Dividends	15,17	(9,940)	(11,134)	(17,858)	(16,471)
Cash flow from/(used in) financing activities		(133,759)	180,479	(294,860)	667,096
Investing Activities					
Capital and office expenditures	17	(115,040)	(75,202)	(190,067)	(115,547)
Bruin acquisition	6	—	(2,008)	—	(420,249)
Dunn County acquisition	6	—	(304,888)	—	(304,888)
Property and land acquisitions		(1,469)	(1,552)	(3,410)	(4,023)
Property divestments	9,17	(4,462)	(12)	2,119	3,998
Cash flow from/(used in) investing activities		(120,971)	(383,662)	(191,358)	(840,709)
Effect of exchange rate changes on cash & cash equivalents		6,545	2,969	3,424	5,258
Change in cash and cash equivalents		2,675	(89,748)	(35,942)	(29,227)
Cash and cash equivalents, beginning of period		22,731	150,466	61,348	89,945
Cash and cash equivalents, end of period		$ 25,406	$ 60,718	$ 25,406	$ 60,718

The accompanying notes to the Condensed Consolidated Financial Statements are an integral part of these statements.

Notes to Condensed Consolidated Financial Statements
(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation (the "Company" or "Enerplus") including its Canadian and United States ("U.S.") subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' corporate offices are located in Calgary, Alberta, Canada and Denver, Colorado, United States.

2) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three and six months ended June 30, 2022 and the 2021 comparative periods. In the fourth quarter of 2021, the Company elected to change its reporting currency from Canadian dollars to U.S. dollars since the majority of its crude oil and natural gas properties are located in the U.S., and to facilitate a more direct comparison to other U.S. exploration and development companies. The change in reporting currency is a voluntary change which is accounted for retrospectively. All prior period amounts have been restated to reflect U.S. dollars as the reporting currency. Certain prior period amounts have been reclassified to conform with current period presentation. Certain information and notes normally included with the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with Enerplus' annual audited Consolidated Financial Statements as of December 31, 2021.

These unaudited interim Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments necessary to present fairly the financial position and results of the Company as at and for the periods presented.

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Actual results could differ from these estimates, and changes in estimates are recorded when known. Significant estimates made by management include those that relate to: crude oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment of property, plant and equipment, asset retirement obligations, income taxes, ability to realize deferred income tax assets and the fair value of derivative instruments. The estimation of crude oil and natural gas reserves and the related present value of future cash flows involves the use of independent reservoir engineering specialists and numerous inputs and assumptions including forecasted production volumes, forecasted operating, royalty and capital cost assumptions and assumptions around commodity pricing. Inflation and discount rates impacting various items within the Company's financial statements are also subject to management estimation. When estimating the present value of future cash flows, the discount rate implicitly considers the potential impacts, if any, due to climate change factors. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions.

3) ACCOUNTS RECEIVABLE

($ thousands)	June 30, 2022	December 31, 2021
Accrued revenue	$ 366,422	$ 208,160
Accounts receivable – trade	25,369	23,697
Allowance for doubtful accounts	(3,980)	(3,869)
Total accounts receivable, net of allowance for doubtful accounts	$ 387,811	$ 227,988

4) PROPERTY, PLANT AND EQUIPMENT ("PP&E")

At June 30, 2022 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Crude oil and natural gas properties(1)	$ 13,220,036	$ (11,839,785)	$ 1,380,251
Other capital assets	102,323	(90,171)	12,152
Total PP&E	$ 13,322,359	$ (11,929,956)	$ 1,392,403

At December 31, 2021 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Crude oil and natural gas properties(1)	$ 13,075,987	$ (11,822,482)	$ 1,253,505
Other capital assets	103,355	(89,468)	13,887
Total PP&E	$ 13,179,342	$ (11,911,950)	$ 1,267,392

(1) All of the Company's unproved properties are included in the full cost pool.

5) IMPAIRMENT

No asset impairment was recorded during the three and six months ended June 30, 2022 (2021 – nil and $3.4 million in the Canadian cost center, respectively). The primary factors that affect ceiling values include first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, and production levels.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from June 30, 2021 through June 30, 2022:

Period	WTI Crude Oil $/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas $/Mcf	Exchange Rate CDN$/US$
Q2 2022	$ 85.82	$ 104.78	$ 5.14	0.79
Q1 2022	75.28	90.17	4.11	0.80
Q4 2021	66.55	78.15	3.64	0.80
Q3 2021	57.64	67.27	3.00	0.79
Q2 2021	49.72	58.31	2.47	0.78

6) ACQUISITIONS & DIVESTMENT

a) Bruin E&P HoldCo, LLC Acquisition

On January 25, 2021, Enerplus Resources (USA) Corporation, an indirect wholly-owned subsidiary of Enerplus entered into a purchase agreement to acquire all of the equity interests of Bruin E&P HoldCo, LLC ("Bruin") for total cash consideration of $465.0 million, subject to certain purchase price adjustments. Bruin was a private company that held crude oil and natural gas interests in certain properties located in the Williston Basin, North Dakota. The effective date of the acquisition was January 1, 2021 and the acquisition was completed on March 10, 2021.

The transaction was accounted for as an acquisition of a business. The purchase price equation was determined following the closing date, during which time the value of the net assets and liabilities acquired was revised as indicated in the agreement and is reflected in the final purchase price equation as follows:

($ thousands)	At March 10, 2021
Consideration	
Purchase Price	$ 465,000
Purchase price adjustments	(44,751)
Total consideration	$ 420,249
Fair value of identifiable assets and liabilities of Bruin	
Other current assets	1,667
Property, plant and equipment	542,190
Right of use assets	1,892
Accounts payable	(25,257)
Asset retirement obligation	(21,964)
Commodity contract liabilities	(76,387)
Lease liabilities	(1,892)
Total identifiable net assets	$ 420,249

The above purchase price equation includes $2.0 million of final adjustments that were recorded during the three months ended June 30, 2021.

b) Dunn County Acquisition

On April 30, 2021, the Company acquired assets in Dunn County, North Dakota from Hess Bakken Investments II, LLC for total cash consideration of $312.0 million, subject to customary purchase price adjustments. After purchase price adjustments, the purchase consideration including capitalized transaction costs was $306.8 million. The transaction was recorded as an asset acquisition.

c) Sleeping Giant and Russian Creek Divestment

On November 2, 2021, the Company completed a disposition of its interests in the Sleeping Giant field in Montana and the Russian Creek area in North Dakota in the Williston Basin, for total cash consideration of $115.0 million, subject to customary purchase price adjustments. After purchase price adjustments and transaction costs, adjusted proceeds were $107.8 million. In addition, Enerplus may receive up to $5.0 million in contingent payments if the WTI oil price averages over $65 per barrel in 2022 and over $60 per barrel in 2023, with amounts payable on January 31, 2023 and January 31, 2024, respectively. The fair value of the contingent payments have been recorded as part of Other Current Assets and Other Long-Term assets.

7) ACCOUNTS PAYABLE

($ thousands)	June 30, 2022	December 31, 2021
Accrued payables	$ 174,164	$ 106,222
Accounts payable – trade	289,066	260,786
Total accounts payable	$ 463,230	$ 367,008

8) DEBT

($ thousands)	June 30, 2022	December 31, 2021
Current:		
Senior notes	$ 80,600	$ 100,600
Long-term:		
Bank credit facilities	347,189	397,971
Senior notes	143,600	203,200
Total debt	$ 571,389	$ 701,771

Bank Credit Facilities

During the six months ended June 30, 2022, Enerplus converted its senior unsecured, covenant-based, $400 million term loan maturing on March 9, 2024 into a revolving bank credit facility with no other amendments. Debt issuance costs were netted against the debt on issuance and are being amortized over the three-year term with $1.5 million of unamortized debt issuance costs remaining at June 30, 2022.

Enerplus also has a senior unsecured, covenant-based, $900 million sustainability linked lending ("SLL") bank credit facility that matures on October 31, 2025. Debt issuance costs in relation to the SLL bank credit facility are being amortized over the four and a half year term with $1.3 million of debt issuance costs remaining unamortized at June 30, 2022.

For the three and six months ended June 30, 2022, total amortization of debt issuance costs amounted to $0.3 million and $0.7 million, respectively (2021 – $0.2 million and $0.3 million, respectively).

Senior Notes

During the three months ended June 30, 2022, Enerplus made its third $59.6 million principal repayment on its 2012 senior notes and repaid a $20 million bullet payment outstanding. The terms and rates of the Company's outstanding senior notes are provided below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	$200,000	$105,000
May 15, 2012	May 15 and Nov 15	2 equal annual installments beginning May 15, 2023	4.40%	$355,000	$119,200
				Total carrying value at June 30, 2022	$ 224,200

Capital Management

Enerplus' capital consists of cash and cash equivalents, debt and shareholders' equity. The Company's objective for managing capital is to prioritize balance sheet strength while maintaining flexibility to repay debt, fund sustaining capital, return capital to shareholders or fund future production growth. Capital management measures are useful to investors and securities analysts in analyzing operating and financial performance, leverage, and liquidity. Enerplus' key capital management measures are as follows:

a) Net Debt

Enerplus calculates net debt as current and long-term debt associated with senior notes plus any outstanding bank credit facility balances, minus cash and cash equivalents.

($ thousands)	June 30, 2022	December 31, 2021
Current portion of long-term debt	$ 80,600	$ 100,600
Long-term debt	490,789	601,171
Total debt	$ 571,389	$ 701,771
Less: Cash and cash equivalents	(25,406)	(61,348)
Net debt	$ 545,983	$ 640,423

b) Adjusted funds flow

Adjusted funds flow is calculated as cash flow from operating activities before asset retirement obligation expenditures and changes in non-cash operating working capital.

	Three months ended June 30,		Six months ended June 30,	
($thousands)	2022	2021	2022	2021
Cash flow from/(used in) operating activities	$ 250,860	$ 110,466	$ 446,852	$ 139,128
Asset retirement obligation settlements	2,349	1,155	11,144	6,780
Changes in non-cash operating working capital	44,184	38,350	101,292	104,917
Adjusted funds flow	$ 297,393	$ 149,971	$ 559,288	$ 250,825

c) Net debt to adjusted funds flow ratio

The net debt to adjusted funds flow ratio is calculated as net debt divided by a trailing twelve months of adjusted funds flow.

($thousands)	June 30, 2022	December 31, 2021
Net debt	$ 545,983	$ 640,423
Trailing adjusted funds flow	1,020,896	712,433
Net debt to adjusted funds flow ratio	0.5x	0.9x

9) ASSET RETIREMENT OBLIGATION (“ARO”)

($ thousands)	June 30, 2022	December 31, 2021
Balance, beginning of year	$ 132,814	$ 102,325
Change in estimates	35,831	26,586
Property acquisitions and development activity	2,453	1,304
Bruin acquisition (Note 6)	—	21,964
Dunn County acquisition (Note 6)	—	5,880
Divestments (Note 6)	(92)	(13,525)
Settlements	(11,144)	(12,951)
Government assistance	(497)	(4,594)
Accretion expense	3,600	5,825
Balance, end of period	$ 162,965	$ 132,814

Enerplus has estimated the present value of its ARO to be $163.0 million at June 30, 2022 based on a total undiscounted uninflated liability of $352.3 million (December 31, 2021 – $132.8 million and $303.3 million, respectively).

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 benefited from $0.1 million and $0.5 million, respectively (2021 – $0.6 million and $1.9 million, respectively), in government assistance, which has been recorded as other income in the Condensed Consolidated Statements of Income/(Loss).

For the six months ended June 30, 2022, Enerplus recognized $13.1 million as part of other expense in the Condensed Consolidated Statements of Income/(Loss) to fund abandonment and reclamation obligation requirements on previously disposed of assets (2021 – nil).

10) LEASES

The Company has entered into various lease contracts related to office space, drilling rig commitments, vehicles and other equipment. Leases are entered into and exited in coordination with specific business requirements which include the assessment of the appropriate durations for the related leased assets. Short-term leases with a lease term of 12 months or less are not recorded on the Condensed Consolidated Balance Sheets. Such items are charged to operating expenses or general and administrative expenses, as appropriate, in the Condensed Consolidated Statements of Income/(Loss), unless the costs are included in the carrying amount of another asset in accordance with U.S. GAAP.

($ thousands)	June 30, 2022	December 31, 2021
Assets		
Operating right-of-use assets	$ 22,772	$ 26,118
Liabilities		
Current operating lease liabilities	$ 8,327	$ 10,618
Non-current operating lease liabilities	17,017	18,265
Total lease liabilities	$ 25,344	$ 28,883
Weighted average remaining lease term (years)		
Operating leases	2.8	3.3
Weighted average discount rate		
Operating leases	3.4%	3.4%

The Company's lease contract expenditures/(income) for the three months ended June 30, 2022 and 2021 are as follows:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2022	2021	2022	2021
Operating lease cost	$ 2,947	$ 2,778	$ 5,847	$ 5,635
Variable lease cost	1,156	271	2,301	295
Short-term lease cost	920	750	2,571	1,305
Sublease income	(358)	(282)	(592)	(473)
Total	$ 4,665	$ 3,517	$ 10,127	$ 6,762

Variable lease payments are determined through analysis of day rate fees under applicable rig contracts. The amounts in the table above are recorded as part of general and administrative or operating expenses or property, plant, and equipment depending on the nature of the contract to which they relate. Although Enerplus has various leases containing extensions and/or termination options, none were determined to be reasonably certain to be exercised. As a result, none of these options are recognized as part of the ROU assets or lease liabilities at June 30, 2022 or December 31, 2021.

Maturities of lease liabilities, all of which are classified as operating leases at June 30, 2022 are as follows:

($ thousands)	Operating Leases
2022	$ 5,988
2023	11,137
2024	6,312
2025	1,120
2026	966
After 2026	1,153
Total lease payments	$ 26,676
Less imputed interest	(1,332)
Total discounted lease payments	$ 25,344
Current portion of lease liabilities	$ 8,327
Non-current portion of lease liabilities	$ 17,017

Supplemental information related to leases is as follows:

($ thousands)	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 amounts paid to settle lease liabilities:				
Operating cash flow used for operating leases	$ 2,617	$ 2,993	$ 5,807	$ 6,071
Right-of-use assets obtained/(terminated) in exchange for lease liabilities:				
Operating leases	$ 1,362	$ 6,494	$ 2,314	$ 8,657

11) CRUDE OIL AND NATURAL GAS SALES

Crude oil and natural gas revenue by country and by product for the three and six months ended June 30, 2022 and 2021 are as follows:

Three months ended June 30, 2022 ($ thousands)	**Total revenue**	**Crude oil**(1)	**Natural gas**(1)	**Natural gas liquids**(1)	**Other**(2)
United States	$ 578,260	$ 433,774	$ 119,972	$ 24,510	$ 4
Canada	49,757	43,449	4,481	1,717	110
Total	$ 628,017	$ 477,223	$ 124,453	$ 26,227	$ 114

Three months ended June 30, 2021 ($ thousands)	**Total revenue**	**Crude oil**(1)	**Natural gas**(1)	**Natural gas liquids**(1)	**Other**(2)
United States	$ 303,508	$ 255,386	$ 35,728	$ 12,388	$ 6
Canada	29,914	26,980	1,844	954	136
Total	$ 333,422	$ 282,366	$ 37,572	$ 13,342	$ 142

Six months ended June 30, 2022 ($ thousands)	**Total revenue**	**Crude oil**(1)	**Natural gas**(1)	**Natural gas liquids**(1)	**Other**(2)
United States	$ 1,050,507	$ 791,431	$ 207,468	$ 51,600	$ 8
Canada	90,662	79,996	7,262	3,109	295
Total	$ 1,141,169	$ 871,427	$ 214,730	$ 54,709	$ 303

Six months ended June 30, 2021 ($ thousands)	**Total revenue**	**Crude oil**(1)	**Natural gas**(1)	**Natural gas liquids**(1)	**Other**(2)
United States	$ 504,391	$ 395,676	$ 83,816	$ 24,885	$ 14
Canada	57,421	50,126	4,923	1,998	374
Total	$ 561,812	$ 445,802	$ 88,739	$ 26,883	$ 388

(1) U.S. sales of crude oil and natural gas relate primarily to the Company's North Dakota and Marcellus properties, respectively. Canadian crude oil sales relate primarily to the Company's waterflood properties.
(2) Includes third party processing income.

12) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
General and administrative expense(1)	$ 9,291	$ 8,760	$ 20,394	$ 19,021
Share-based compensation expense	5,396	1,374	11,874	3,954
General and administrative expense	$ 14,687	$ 10,134	$ 32,268	$ 22,975

(1) Includes a non-cash lease credit of $99 and $194, respectively for the three and six months ended June 30, 2022 (2021 – credit of $91 and $181, respectively).

13) FOREIGN EXCHANGE

($ thousands)	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Realized:				
Foreign exchange (gain)/loss	$ 185	$ 2,905	$ (109)	$ 2,368
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	(125)	(1,975)	(115)	(1,619)
Unrealized:				
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	(3,292)	6,848	(2,121)	7,005
Foreign exchange (gain)/loss	$ (3,232)	$ 7,778	$ (2,345)	$ 7,754

14) INCOME TAXES

($ thousands)	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Current tax				
United States	$ 12,000	$ 3,415	$ 17,000	$ 3,415
Canada	—	—	—	—
Current tax expense/(recovery)	12,000	3,415	17,000	3,415
Deferred tax				
United States	$ 73,898	$ 25,380	$ 130,366	$ 44,320
Canada	(2,197)	(34,389)	(48,883)	(44,672)
Deferred tax expense/(recovery)	71,701	(9,009)	81,483	(352)
Income tax expense/(recovery)	$ 83,701	$ (5,594)	$ 98,483	$ 3,063

The difference between the expected income taxes based on the statutory income tax rate and the effective income taxes for the current and prior period is impacted by expected annual earnings, recognition or reversal of valuation allowance, foreign rate differentials for foreign operations, statutory and other rate differentials, non-taxable portions of capital gains and losses, and share-based compensation.

The Company's overall net deferred income tax asset was $294.9 million at June 30, 2022 (December 31, 2021 – $380.9 million).

15) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued: (thousands)	Six months ended June 30, 2022 Shares	Six months ended June 30, 2022 Amount	Year ended December 31, 2021 Shares	Year ended December 31, 2021 Amount
Balance, beginning of year	243,852	$ 3,094,061	222,548	$ 3,113,829
Issued/(Purchased) for cash:				
Issue of shares (net of tax effected issue costs)	—	—	33,062	99,516
Purchase of common shares under Normal Course Issuer Bid	(10,213)	(100,416)	(12,898)	(128,686)
Non-cash:				
Share-based compensation – treasury settled(1)	1,240	7,959	1,140	9,402
Balance, end of period	234,879	$ 3,001,604	243,852	$ 3,094,061

(1) The amount of shares issued on long-term incentive settlement is net of employee withholding taxes.

Dividends declared to shareholders for the three and six months ended June 30, 2022 were $9.9 million and $17.9 million, respectively (2021 – $9.1 million and $14.7 million, respectively). Subsequent to the quarter, the Board of Directors approved a 16% increase to the dividend to $0.05 per share to be effective for the September 2022 payment.

During the three months ended June 30, 2022, 7,078,222 common shares were repurchased and cancelled under the Normal Course Issuer Bid ("NCIB") at an average price of $13.13 per share, for total consideration of $92.9 million. Of the amount paid, $69.1 million was charged to share capital and $23.8 million was credited to accumulated deficit. 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. The Company did not have an NCIB in place during the three and six months ended June 30, 2021.

Subsequent to June 30, 2022, the Company repurchased 2,455,168 common shares under the current NCIB at an average price of $12.81 per 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 program to purchase an additional 10% of the public float during the following 12-month period. The NCIB renewal remains subject to approval by the Toronto Stock Exchange.

b) Share-based Compensation

The following table summarizes Enerplus' share-based compensation expense, which is included in General and Administrative expense on the Condensed Consolidated Statements of Income/(Loss):

($ thousands)	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:				
Long-term incentive plans expense	$ 296	$ 1,858	$ 2,394	$ 4,017
Non-Cash:				
Long-term incentive plans expense	5,733	72	10,488	964
Equity swap gain	(633)	(556)	(1,008)	(1,027)
Share-based compensation expense	$ 5,396	$ 1,374	$ 11,874	$ 3,954

Long-term Incentive ("LTI") Plans

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU"), Director Deferred Share Unit ("DSU") and Director RSU ("DRSU") activity for the six months ended June 30, 2022:

	Cash-settled LTI plans	Equity-settled LTI plans		Total
(thousands of units)	Director Plans	PSU(1)	RSU	
Balance, beginning of year	589	3,981	3,065	7,635
Granted	83	766	803	1,652
Vested	(45)	(827)	(1,300)	(2,172)
Forfeited	—	(38)	(72)	(110)
Balance, end of period	627	3,882	2,496	7,005

(1) Based on underlying awards before any effect of the performance multiplier.

Cash-settled LTI Plans

For the three and six months ended June 30, 2022, the Company recorded a cash share-based compensation expense of $0.3 million and $2.4 million, respectively (2021 – $1.8 million and $4.0 million, respectively).

As of June 30, 2022, a liability of $8.3 million (December 31, 2021 – $6.3 million) with respect to the Director DSU and DRSU plans has been recorded to Accounts Payable on the Condensed Consolidated Balance Sheets.

Equity-settled LTI Plans

The following table summarizes the cumulative share-based compensation expense recognized to-date, which is recorded as Paid-in Capital on the Condensed Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At June 30, 2022 ($ thousands, except for years)	PSU[(1)]	RSU	Total
Cumulative recognized share-based compensation expense	$ 11,914	$ 7,528	$ 19,442
Unrecognized share-based compensation expense	11,066	8,082	19,148
Fair value	$ 22,980	$ 15,610	$ 38,590
Weighted-average remaining contractual term (years)	2.0	1.6	

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the three and six months ended June 30, 2022, nil and $11.6 million, respectively (2021 – nil and $3.6 million, respectively) in cash withholding taxes were paid.

c) Basic and Diluted Net Income/(Loss) Per Share

Net income/(loss) per share has been determined as follows:

	Three months ended June 30,		Six months ended June 30,	
(thousands, except per share amounts)	2022	2021	2022	2021
Net income/(loss)	$ 244,406	$ (50,933)	$ 277,649	$ (40,584)
Weighted average shares outstanding – Basic	239,277	256,750	241,022	250,443
Dilutive impact of share-based compensation	7,939	—	7,935	—
Weighted average shares outstanding – Diluted[(1)]	247,216	256,750	248,957	250,443
Net income/(loss) per share				
Basic	$ 1.01	$ (0.20)	$ 1.15	$ (0.16)
Diluted	$ 0.99	$ (0.20)	$ 1.12	$ (0.16)

(1) For the three and six months ended June 30, 2021, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the net loss per share.

16) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At June 30, 2022, the carrying value of cash and cash equivalents, accounts receivable, and accounts payable approximated their fair value due to the short-term nature of these instruments. The fair values of the bank credit facilities approximate their carrying values as they bear interest at floating rates and the credit spread approximates current market rates.

At June 30, 2022, the senior notes had a carrying value of $224.2 million and a fair value of $219.7 million (December 31, 2021 – $303.8 million and $304.1 million, respectively). The fair value of the senior notes is estimated based on the amount that Enerplus would have to pay a third party to assume the debt, including the credit spread for the difference between the issue rate and the period end market rate. The period end market rate is estimated by comparing the debt to new issuances (secured or unsecured) and secondary trades of similar size and credit statistics for both public and private debt.

The fair value of derivative contracts, senior notes and bank credit facilities are considered level 2 fair value measurements. There were no transfers between fair value hierarchy levels during the period.

b) Derivative Financial Instruments

The derivative financial assets and liabilities on the Condensed Consolidated Balance Sheets result from recording derivative financial instruments at fair value. At June 30, 2022, Enerplus has commodity and contingent consideration contracts. See Note 6 regarding the contingent consideration contract.

The following table summarizes the income statement change in fair value for the three and six months ended June 30, 2022 and 2021:

Gain/(Loss) ($ thousands)	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021	Income Statement Presentation
Equity Swaps	$ 633	$ 556	$ 1,008	$ 1,027	G&A
Commodity Contracts:					
Crude oil	68,513	(119,652)	(27,193)	(161,509)	Commodity derivative instruments
Natural gas	22,129	(11,184)	(15,872)	(10,156)	
Total Unrealized Gain/(Loss)	$ 91,275	$ (130,280)	$ (42,057)	$ (170,638)	

The following table summarizes the effect of Enerplus' commodity contracts on the Condensed Consolidated Statements of Income/(Loss):

($ thousands)	Three months ended June 30, 2022	Three months ended June 30, 2021	Six months ended June 30, 2022	Six months ended June 30, 2021
Unrealized change in fair value gain/(loss)	$ 90,642	$ (130,836)	$ (43,065)	$ (171,665)
Net realized gain/(loss)	(138,195)	(30,986)	(211,298)	(46,420)
Commodity contracts gain/(loss)	$ (47,553)	$ (161,822)	$ (254,363)	$ (218,085)

The following table summarizes the presentation of fair values at the respective period ends:

	June 30, 2022				December 31, 2021		
	Assets		Liabilities		Assets	Liabilities	
($ thousands)	Current	Long-term	Current	Long-term	Current	Current	Long-term
Equity Swaps	$ —	$ —	$ —	$ —	$ —	$ 969	$ —
Commodity Contracts:							
Crude oil	273	2,298	155,790	8,054	1,771	141,364	7,098
Natural gas	3,274	—	16,114	—	3,897	867	—
Total	$ 3,547	$ 2,298	$ 171,904	$ 8,054	$ 5,668	$ 143,200	$ 7,098

The fair value of commodity contracts and the equity swaps is estimated based on commodity and option pricing models that incorporate various factors including forecasted commodity prices, volatility and the credit risk of the entities party to the contract. Changes and variability in commodity prices over the term of the contracts can result in material differences between the estimated fair value at a point in time and the actual settlement amounts.

On March 10, 2021, the outstanding crude oil commodity contracts acquired with the Bruin acquisition were recorded at fair value. Realized and unrealized gains and losses on the acquired contracts are recognized in the Condensed Consolidated Statement of Income/(Loss) and the Condensed Consolidated Balance Sheets to reflect changes in crude oil prices from the closing date of the Bruin acquisition.

At June 30, 2022, the fair value of Enerplus' commodity contracts totaled a net liability of $174.1 million (December 31, 2021 – $143.7 million). Of this total net liability, $30.5 million (December 31, 2021 – $40.2 million) related to Bruin contracts, with $10.3 million (December 31, 2021 – $22.8 million) remaining from the original $76.4 million liability acquired from Bruin on March 10, 2021.

c) Risk Management

In the normal course of operations, Enerplus is exposed to various market risks, including commodity prices, foreign exchange, interest rates, equity prices, credit risk, liquidity risk, and the risks associated with environmental/climate change risk, social and governance regulation, and compliance.

i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

Commodity Price Risk:

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes. The following tables summarize Enerplus' price risk management positions at August 3, 2022:

Crude Oil Instruments:

Instrument Type(1)(2)	Jul 1, 2022 – Sep 30, 2022		Oct 1, 2022 - Dec 31, 2022	
	bbls/day	US$/bbl	bbls/day	US$/bbl
WTI Purchased Put	17,000	50.00	17,000	50.00
WTI Sold Put	17,000	40.00	17,000	40.00
WTI Sold Call	17,000	57.91	17,000	57.91
WTI Sold Swap(3)	4,500	42.31	1,834	42.65
WTI Purchased Swap	4,500	66.79	1,834	64.55
WTI Sold Swap	6,000	110.25	—	—
WTI Purchased Swap	6,000	93.75	—	—

	Jan 1, 2023 - Jun 30, 2023		Jul 1, 2023 - Oct 31, 2023		Nov 1, 2023 - Dec 31, 2023	
	bbls/day	US$/bbl	bbls/day	US$/bbl	bbls/day	US$/bbl
WTI Purchased Put	15,000	79.33	5,000	85.00	5,000	85.00
WTI Sold Put	15,000	61.67	5,000	65.00	5,000	65.00
WTI Sold Call	15,000	114.31	5,000	128.16	5,000	128.16
WTI Purchased Swap	250	64.85	250	64.85	—	—
WTI Sold Swap(3)	250	42.10	250	42.10	—	—
WTI Purchased Put(3)	2,000	5.00	2,000	5.00	2,000	5.00
WTI Sold Call(3)	2,000	75.00	2,000	75.00	2,000	75.00

(1) The total average deferred premium spent on the Company's outstanding crude oil contracts is $1.50/bbl from July 1, 2022 - December 31, 2022 and $1.25/bbl from January 1, 2023 – June 30, 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.

Natural Gas Instruments:

Instrument Type(1)	Jul 1, 2022 – Oct 31, 2022		Nov 1, 2022 – Mar 31, 2023	
	MMcf/day	US$/Mcf	MMcf/day	US$/Mcf
NYMEX Swap	40.0	3.40	—	—
NYMEX Purchased Put	60.0	3.77	50.0	6.50
NYMEX Sold Call	60.0	4.50	50.0	16.41

(1) Transactions with a common term have been aggregated and presented at weighted average prices/Mcf.

Foreign Exchange Risk & Net Investment Hedge:

Enerplus is exposed to foreign exchange risk as it relates to certain activity transacted in Canadian or United States dollars. Enerplus has a U.S. dollar reporting currency, however Enerplus' parent company has a Canadian functional currency. Activity in the Canadian parent company that is transacted in U.S. dollars results in realized and unrealized foreign exchange gains and losses and is recorded on the Condensed Consolidated Statements of Income/(Loss).

Enerplus may designate certain U.S. dollar denominated debt held in the parent entity as a hedge of its net investment in its U.S. subsidiary, which has a U.S. dollar functional currency. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in Other Comprehensive Income/(Loss), net of tax, and are limited by the cumulative translation gain or loss on the net investment in the foreign subsidiary. At June 30, 2022, $224.2 million of senior notes and $347.2 million drawn on the bank credit facilities were designated as net investment hedges (December 31, 2021 – $303.8 million of the senior notes and $400 million of the term loan, respectively). For the three and six months ended June 30, 2022, Other Comprehensive Income/(Loss) included an unrealized loss of $14.1 million and $8.7 million, respectively on Enerplus' U.S. denominated senior notes and revolving bank credit facilities (2021 – $10.2 million and $15.9 million gain, respectively).

Interest Rate Risk:

The Company's senior notes bear interest at fixed rates while the bank credit facilities bear interest at floating rates. At June 30, 2022, approximately 39% of Enerplus' debt was based on fixed interest rates and 61% on floating interest rates (December 31, 2021 – 43% fixed and 57% floating), with weighted average interest rates of 4.2% and 2.2%, respectively. At June 30, 2022, Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 15. The Company may enter into various equity swaps to fix the future settlement cost on a portion of its cash settled LTI plans. At June 30, 2022, Enerplus did not have any equity swaps outstanding.

ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables. Enerplus has appropriate policies and procedures in place to manage its credit risk; however, given the volatility in commodity prices, Enerplus is subject to an increased risk of financial loss due to non-performance or insolvency of its counterparties.

Enerplus mitigates credit risk through credit management techniques, including conducting financial assessments to establish and monitor counterparties' credit worthiness, setting exposure limits, monitoring exposures against these limits and obtaining financial assurances such as letters of credit, parental guarantees, or third party credit insurance where warranted. Enerplus monitors and manages its concentration of counterparty credit risk on an ongoing basis.

The Company's maximum credit exposure consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At June 30, 2022, approximately 89% of Enerplus' marketing receivables were with companies considered investment grade (December 31, 2021 – 83%).

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts of future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at June 30, 2022 was $4.0 million (December 31, 2021 – $3.9 million).

iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash and cash equivalents) and shareholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus strives to balance the portion of debt and equity in its capital structure given its current crude oil and natural gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, dividends, share repurchases, access to capital markets, as well as acquisition and divestment activity.

At June 30, 2022, Enerplus was in full compliance with all covenants under the bank credit facilities and outstanding senior notes. If the Company breaches or anticipates breaching its covenants, the Company may be required to repay, refinance, or renegotiate the terms of the debt.

iv) Climate Change Risk

Enerplus is exposed to climate change risks through changing regulation, potential access to capital, capital spending plans and the impact of climate related events on the Company's financial position. The Company did not recognize amounts in respect of climate change risk in the Condensed Consolidated Financial Statements at and for the three and six months ended June 30, 2022 as there have been no material changes since management's risk assessment at December 31, 2021.

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2022	2021	2022	2021
Accounts receivable	$ (105,492)	$ (68,320)	$ (160,083)	$ (120,774)
Other assets	487	(1,179)	4,792	1,268
Accounts payable – operating	60,821	31,149	53,999	14,589
Non-cash operating activities	$ (44,184)	$ (38,350)	$ (101,292)	$ (104,917)

b) Changes in Non-Cash Financing Working Capital

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2022	2021	2022	2021
Dividends payable	$ —	$ (2,046)	$ —	$ (1,749)
Non-cash financing activities	$ —	$ (2,046)	$ —	$ (1,749)

c) Changes in Non-Cash Investing Working Capital

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2022	2021	2022	2021
Accounts payable – investing(1)	$ 17,984	$ 31,069	$ 42,290	$ 42,844

(1) Relates to changes in accounts payable for capital and office expenditures and included in capital and office expenditures on the Condensed Consolidated Statements of Cash Flows.

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2022	2021	2022	2021
Settlement on divestment(2)	$ 13,053	$ —	$ 13,053	$ —

(2) Relates to funding abandonment and reclamation obligation requirements on previously disposed assets. Refer to Note 9.

d) Cash Income Taxes and Interest Payments

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2022	2021	2022	2021
Income taxes paid/(received)	$ 2,607	$ 3,414	$ 2,614	$ 3,418
Interest paid	$ 7,193	$ 9,826	$ 12,399	$ 12,364

18) SUBSEQUENT EVENT

On July 28, 2022, the Company announced it had entered into a definitive agreement to sell certain Canadian assets ("the Assets") located in Alberta for total consideration of CDN$140 million ($109 million), subject to customary purchase price adjustments. The total consideration comprises cash of CDN$81 million, 3.0 million common shares in the purchaser valued at CDN$14 million based on its last five trading days volume weighted average share price, and a CDN$45 million monthly amortizing, interest-bearing loan which Enerplus will provide to the purchaser that is secured by certain of the Assets and which must be repaid in full by October 31, 2024.

BOARD OF DIRECTORS

Hilary A. Foulkes(1)(2)
Corporate Director
Calgary, Alberta

Judith D. Buie(3)(5)(7)
Corporate Director
Houston, Texas

Karen E. Clarke-Whistler(3)(7)(9)
Corporate Director
Toronto, Ontario

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Robert B. Hodgins(4)(9)
Corporate Director
Calgary, Alberta

Mark A. Houser(5)(7)(9)
Corporate Director
Houston, Texas

Susan M. MacKenzie(7)(10)
Corporate Director
Calgary, Alberta

Jeffrey W. Sheets(6)(9)
Corporate Director
Houston, Texas

Sheldon B. Steeves(5)(8)
Corporate Director
Calgary, Alberta

(1) Chair of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chair of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chair of the Audit & Risk Management Committee
(7) Member of the Reserves, Safety & Social Responsibility Committee
(8) Chair of the Reserves, Safety & Social Responsibility Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chair of the Compensation & Human Resources Committee

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Wade D. Hutchings
Senior Vice President & Chief Operating Officer

Jodine J. Jenson Labrie
Senior Vice President & Chief Financial Officer

Garth R. Doll
Vice President, Marketing

Terry S. Eichinger
Vice President, Drilling, Completions & Operations Support

Nathan D. Fisher
Vice President, United States Business Unit

Daniel J. Fitzgerald
Vice President, Business Development

John E. Hoffman
Vice President, Digital Technology & Corporate Sustainability

David A. McCoy
Vice President, General Counsel & Corporate Secretary

Shaina B. Morihira
Vice President, Finance

Pamela A. Ramotowski
Vice President, People & Culture

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

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AUDITORS

KPMG LLP
Calgary, Alberta

TRANSFER AGENT

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American Stock Transfer & Trust Company (United States)
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New York Stock Exchange: ERF

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ABBREVIATIONS

bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons
Bcf	billion cubic feet
BOE	barrels of oil equivalent
Brent	crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $U.S. dollars
DAPL	Dakota Access Pipeline
LTI	long-term incentive
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMcf	million cubic feet
MMBOE	million barrels of oil equivalent
MSW	Mixed Sweet Blend at Edmonton, Alberta, the benchmark for Canadian light sweet crude oil pricing
NCIB	Normal Course Issuer Bid
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
SBC	share based compensation
Transco Leidy	Price benchmark for Marcellus natural gas delivered into the Transco pipeline system between Hunterdon County, New Jersey and connections east of the Leidy storage facility in Clinton and Potter Counties in Pennsylvania
Transco Z6 Non-New York	Price benchmark for Marcellus natural gas delivered into the Transco pipeline system from the start of zone 6 at the Virginia-Maryland border to the Linden, New Jersey, compressor station and on the 24-inch pipeline to the Wharton, Pennsylvania, station
U.S. GAAP	accounting principles generally accepted in the United States of America
WCS	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

CANADA

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