enerPLUS

first quarter report

three months ended March 31, 2022

SELECTED FINANCIAL RESULTS

	Three months ended March 31, 2022	2021
Financial (US$, thousands, except ratios)		
Net Income/(Loss)	$ 33,243	$ 10,349
Adjusted Net Income(1)	145,828	43,871
Cash Flow from Operating Activities	195,992	28,662
Adjusted Funds Flow(1)	261,895	100,854
Dividends to Shareholders - Declared	7,918	5,634
Net Debt	572,271	632,200
Capital Spending	99,013	51,818
Property and Land Acquisitions	1,941	497,139
Property Divestments	6,581	4,010
Net Debt to Adjusted Funds Flow Ratio(1)	0.7x	2.2x
Financial per Weighted Average Shares Outstanding		
Net Income/(Loss) - Basic	$ 0.14	$ 0.04
Net Income/(Loss) - Diluted	0.13	0.04
Weighted Average Number of Shares Outstanding (000's) - Basic	242,787	244,066
Weighted Average Number of Shares Outstanding (000's) - Diluted	249,337	246,898
Selected Financial Results per BOE(2)(3)		
Crude Oil & Natural Gas Sales(4)	$ 61.84	$ 34.43
Commodity Derivative Instruments	(8.81)	(2.32)
Operating Expenses	(10.03)	(7.71)
Transportation Costs	(4.32)	(3.91)
Production Taxes	(4.26)	(2.09)
General and Administrative Expenses	(1.35)	(1.57)
Cash Share-Based Compensation	(0.25)	(0.32)
Interest, Foreign Exchange and Other Expenses	(0.66)	(1.31)
Current Income Tax Recovery/(Expense)	(0.60)	—
Adjusted Funds Flow(1)	$ 31.56	$ 15.20

SELECTED OPERATING RESULTS

	Three months ended March 31, 2022	2021
Average Daily Production(3)		
Crude Oil (bbls/day)	47,634	34,112
Natural Gas Liquids (bbls/day)	8,377	5,270
Natural Gas (Mcf/day)	217,111	205,949
Total (BOE/day)	92,196	73,707
% Crude Oil and Natural Gas Liquids	61%	53%
Average Selling Price(3)(4)		
Crude Oil (per bbl)	$ 91.95	$ 53.24
Natural Gas Liquids (per bbl)	37.78	28.55
Natural Gas (per Mcf)	4.62	2.76
Net Wells Drilled	15	1

(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 and Other Financial 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 March 31, 2022	2021
WTI crude oil ($/bbl)	$ 94.29	$ 57.84
Brent (ICE) crude oil ($/bbl)	97.38	61.10
NYMEX natural gas – last day ($/Mcf)	4.95	2.69
CDN/US average exchange rate	0.79	0.79

Share Trading Summary For the three months ended March 31, 2022	U.S.(1) - ERF (US$)	CDN(2) - ERF (CDN$)
High	$ 14.59	$ 18.75
Low	$ 10.21	$ 12.96
Close	$ 12.70	$ 15.84

(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

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

HIGHLIGHTS

- Adjusted funds flow[1] was $262 million in the first quarter, which exceeded capital spending of $99 million, generating free cash flow[1] of $163 million
- Estimated 2022 free cash flow[1] is $675 million based on rest of year prices of $85 WTI and $5.00 NYMEX
- Increasing total 2022 cash returns to shareholders to a minimum of $350 million or 50% of annual free cash flow, whichever is greater, through dividends and share repurchases
- Increased quarterly dividend by 30% to $0.043 per share
- Production guidance for 2022 increased to 96,000 – 101,000 BOE per day (from 95,500 – 100,500 BOE per day) due to strong operational execution and optimizations
- Capital spending guidance for 2022 revised to $400 – $440 million (from $370 – $430 million) primarily due to inflationary impacts
- Realized 2022 Bakken oil price expected to be at par with WTI

"Our strong operating performance year to date is continuing to support a robust production outlook," said Ian C. Dundas, President and CEO. "Enerplus remains well positioned to execute its 2022 plan which is expected to deliver record free cash flow and meaningful cash returns to shareholders."

"In conjunction with this outlook, we are enhancing our 2022 return of capital plan by committing to a minimum of $350 million or 50% of free cash flow, whichever is greater, returned to shareholders through dividends and share repurchases."

Dundas continued, "High commodity prices and supply chain tightness are creating inflationary pressures across the industry. We are not immune to these pressures. However, actions we took last year to secure services, equipment and supplies have significantly mitigated the impacts and are enabling us to execute our operating plan efficiently, with no plans to increase activity levels or chase higher, less efficient growth."

FIRST QUARTER SUMMARY

Production in the first quarter of 2022 was 92,196 BOE per day, an increase of 25% compared to the same period a year ago, and 10% lower than the prior quarter. Crude oil and natural gas liquids production in the first quarter of 2022 was 56,011 barrels per day, an increase of 42% compared to the same period a year ago, and 14% lower than the prior quarter. The higher production compared to the same period in 2021 was primarily due to the Company's 2021 Bakken acquisitions and development program. The lower production compared to the prior quarter was due to the planned sequencing of the Company's completions program in North Dakota which included a break in onstream activity between early November 2021 through late March 2022, and the divestment of Montana and Russian Creek interests in the fourth quarter of 2021.

Enerplus reported first quarter 2022 net income of $33.2 million, or $0.13 per share (diluted), compared to net income of $10.3 million, or $0.04 per share (diluted), in the same period in 2021. Adjusted net income[1] for the first quarter of 2022 was $145.8 million, or $0.58 per share (diluted), compared to $43.9 million, or $0.18 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 production and benchmark commodity prices and stronger commodity price realizations during the first quarter of 2022.

Enerplus' first quarter 2022 realized Bakken oil price differential was $0.35 per barrel below WTI, compared to $3.19 per barrel below WTI in the first quarter of 2021. The improved year-over-year Bakken differential was due to an improvement in the supply and demand balance, 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 Bakken oil price to be at par with WTI, compared to $0.50 per barrel below WTI previously.

The Company's realized Marcellus natural gas price differential was $0.01 per Mcf above NYMEX during the first quarter of 2022, compared to $0.15 per Mcf below NYMEX in the first 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. As a result, Enerplus' full-year 2022 Marcellus differential guidance is unchanged at $0.75 per Mcf below NYMEX.

In the first quarter of 2022, Enerplus' operating costs were $10.03 per BOE, compared to $7.71 per BOE during the first quarter of 2021. The increase in per unit operating expenses was due to the Company's higher crude oil weighting in its production mix, contracts with price escalators linked to WTI and the Consumer Price Index, and increased well service activity.

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

Capital spending totaled $99.0 million in the first quarter of 2022. The Company paid $7.9 million in dividends in the quarter and repurchased 3.1 million shares at an average price of $11.87 per share, for total consideration of $37.2 million. Subsequent to March 31, 2022, and up to and including May 4, 2022, Enerplus repurchased 1.5 million shares at an average price of $12.61 per share, for total consideration of $18.9 million.

Enerplus ended the first quarter of 2022 with total debt of $595.0 million and cash of $22.7 million.

ASSET HIGHLIGHTS

Williston Basin production averaged 57,343 BOE per day during the first quarter of 2022, an increase of 51% compared to the same period a year ago, driven by Enerplus' 2021 acquisitions and ongoing development. Williston Basin production was 15% lower than the prior quarter due to the planned sequencing of the Company's completions program which included a break in onstream activity between early November 2021 through late March 2022, and the divestment of Montana and Russian Creek interests in the fourth quarter of 2021. The Company brought two operated wells (100% working interest) on production from a six-well pad at the end of March 2022. The remaining four wells were brought on production subsequent to the quarter-end. Enerplus drilled 14 gross operated wells (12 net) during the first quarter and is continuing to operate two drilling rigs. The second quarter is expected to be Enerplus' most active operational quarter in 2022 with approximately 18 – 21 net wells projected to be brought on production.

Marcellus production averaged 162 MMcf per day during the first quarter of 2022, approximately flat compared to the same period in 2021 and the prior quarter. Canadian waterflood production averaged 5,495 BOE per day during the first quarter of 2022, approximately flat compared to the same period in 2021, and 4% lower than the prior quarter.

INCREASING RETURN OF CAPITAL TO SHAREHOLDERS

Assuming commodity prices of $85 per barrel WTI and $5.00 per Mcf NYMEX for the rest of 2022, Enerplus expects to generate approximately $675 million of annual free cash flow[1], representing a reinvestment rate[1] of less than 40%. Enerplus remains committed to both returning a significant portion of free cash flow to shareholders and reducing debt.

Enerplus' board of directors has approved an increase to the Company's 2022 return of capital plan to a minimum of $350 million or 50% of annual free cash flow, whichever is greater, through dividends and share repurchases.

In connection with this plan, the board has approved a 30% increase to the Company's quarterly dividend to $0.043 per share payable on June 15, 2022 to shareholders of record on May 27, 2022. The increased dividend is equal to approximately $40 million on an annualized basis.

The remaining $310 million or greater of shareholder returns in 2022 are expected to be delivered via the Company's share repurchase program, based on current market conditions. Enerplus plans to repurchase its remaining 8.0 million share authorization under its normal course issuer bid ("NCIB") by the end of July 2022 and renew its NCIB in August 2022 for approximately 10% of the outstanding shares.

Enerplus' approach to share repurchases continues to be grounded in 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.

The remaining 50% of 2022 free cash flow not allocated to shareholder returns is expected to be directed to reinforcing the balance sheet.

2022 GUIDANCE UPDATE

Enerplus is revising its capital spending guidance to $400 to $440 million, from $370 to $430 million previously. The updated guidance is a result of inflationary pressures due to the high commodity price environment and supply chain tightness, along with increased non-operated activity and associated costs. On its operated activity in North Dakota, Enerplus currently projects 2022 wells costs will average approximately $6.5 million compared to its initial budget of $6.0 million, with the increase primarily due to higher diesel and steel costs.

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

In April, severe winter weather in North Dakota temporarily impacted Enerplus' operations. The Company estimates that it lost approximately 1,000 BOE per day of annual average 2022 production due to the storm impacts. However, through strong operational execution and the continued optimization of the Company's development plan, Enerplus has more than offset the impact from weather-related downtime to its annual production forecast. As a result, Enerplus is increasing its guidance to 96,000 to 101,000 BOE per day, compared to 95,500 to 100,500 BOE per day previously. Liquids production guidance has been increased to 58,500 to 62,500 barrels per day, compared to 58,000 to 62,000 barrels per day previously.

Given the constructive outlook for Bakken crude oil prices and strong realizations year to date, Enerplus expects its 2022 realized Bakken oil price to be at par with WTI, compared to $0.50 per barrel below WTI previously.

Due to additional costs incurred to restore production following weather-related downtime, Enerplus is increasing the lower end of its operating cost guidance to $9.75 per BOE, from $9.50 per BOE previously.

As a result of the higher commodity price environment, Enerplus is updating its current tax guidance from $10 million to $20 to $30 million (2% – 3% of adjusted funds flow before tax) for 2022 assuming WTI of $85.00 per barrel and NYMEX of $5.00 per Mcf.

A summary of the Company's 2021 and fourth quarter guidance is provided below.

	Guidance	Previous Guidance
Capital spending	$400 – 440 million	$370 – 430 million
Average total production	96,000 – 101,000 BOE/day	95,500 – 100,500 BOE/day
Average liquids production	58,500 – 62,500 bbls/day	58,000 – 62,000 barrels/day
Average production tax rate (% of net sales, before transportation)	7%	7%
Operating expense	$9.75 – 10.50/BOE	$9.50 – 10.50/BOE
Transportation expense	$4.15/BOE	$4.15/BOE
Cash G&A expense	$1.25/BOE	$1.25/BOE
Current tax expense	$20 – $30 million (2-3% of adjusted funds flow before tax)	$10 million

2021 Full-Year Differential/Basis Outlook[1]		
U.S. Bakken crude oil differential (compared to WTI crude oil)	$0/bbl	$(0.50)/bbl
Marcellus natural gas sales price differential (compared to NYMEX natural gas)	$(0.75)/Mcf	$(0.75)/bbl

(1) Excluding transportation costs.

PRICE RISK MANAGEMENT

The following is a summary of Enerplus' financial commodity hedging contracts at May 4, 2022.

	WTI Crude Oil[1][2] (US$bbl)				NYMEX Natural Gas (US$/Mcf)
	Apr 1, 2022 – June 30, 2022	Apr 1, 2022 – Dec 31, 2022	Jan 1, 2023 – June 30, 2023	Jan 1, 2023 – Dec 31, 2023	Apr 1, 2022 – Oct 31, 2022
Sold Swaps					
Volume (mcf/day)	–	–	–	–	40,000
Sold Swaps	–	–	–	–	$ 3.40
Three Way Collars					
Volume (Mcf/day)	–	–	–	–	60,000
Volume (bbls/day)	12,500	17,000	10,000	2,000	–
Sold Puts	$ 58.00	$ 40.00	$ 60.00	–	–
Purchased Puts	$ 75.00	$ 50.00	$ 76.50	$ 5.00	$ 3.77
Sold Calls	$ 87.63	$ 57.91	$ 107.38	$ 75.00	$ 4.50

(1) The total average deferred premium spent on outstanding hedges is $1.50/bbl from April 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 March 31, 2022, the balance was a liability of $16.3 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.

Q1 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 May 6, 2022 to discuss these results. Details of the conference call are as follows:

Date:	Friday, May 6, 2022
Time:	9:00 AM MT (11:00 AM ET)
Dial-In:	587-880-2171 (Alberta)
	1-888-390-0546 (Toll Free)
Conference ID:	14832308
Audiocast:	https://produceredition.webcasts.com/starthere.jsp?ei=1542034&tp_key=861128c0b5

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:	832308 #

FIRST QUARTER 2022 PRODUCTION AND OPERATIONAL SUMMARY TABLES

Summary of Average Daily Production(1)

	Three months ended March 31, 2022				
	Williston Basin	Marcellus	Canadian Waterfloods	Other(2)	Total
Tight oil (bbl/d)	41,554	—	—	874	42,428
Light & medium oil (bbl/d)	—	—	2,150	22	2,172
Heavy oil (bbl/d)	—	—	3,027	7	3,034
Total crude oil (bbl/d)	**41,554**	**—**	**5,177**	**903**	**47,634**
Natural gas liquids (bbl/d)	**7,979**	**—**	**88**	**310**	**8,377**
Shale gas (Mcf/d)	46,858	162,138	—	922	209,918
Conventional natural gas (Mcf/d)	—	—	1,380	5,813	7,193
Total natrual gas (Mcf/d)	**46,858**	**162,138**	**1,380**	**6,735**	**217,111**
Total Production (BOE/day)	**57,343**	**27,023**	**5,495**	**2,335**	**92,196**

(1) Table may not add due to rounding.

(2) Comprises DJ Basin and non-core properties in Canada.

Summary of Wells Drilled(1)

	Three months ended March 31, 2022			
	Operated		Non Operated	
	Gross	Net	Gross	Net
Williston Basin	14	12.0	12	1.5
Marcellus	—	—	16	1.4
Canadian Waterfloods	—	—	—	—
Other(2)	—	—	—	—
Total	**14**	**12.0**	**28**	**2.9**

(1) Table may not add due to rounding.

(2) Comprises DJ Basin and non-core properties in Canada.

Summary of Wells Brought On-Stream[1]

	Three months ended March 31, 2022			
	Operated		Non Operated	
	Gross	Net	Gross	Net
Williston Basin	2	2.0	—	—
Marcellus	—	—	25	1.5
Canadian Waterfloods	—	—	—	—
Other[2]	—	—	—	—
Total	**2**	**2.0**	**25**	**1.5**

(1) Table may not add due to rounding.

(2) Comprises DJ Basin and non-core 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 Management’s Discussion & Analysis 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: updated 2022 production and capital spending guidance; expected capital spending levels in 2022; expectations regarding 2022 and future shareholder returns, including payment of dividends and Enerplus' share repurchase program, the timing and amounts thereof and funding dividends and the share repurchase program from free cash flow; expectations regarding free cash flow generation and capital spending 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 production taxes and updated 2022 guidance with respect thereto; expectations regarding net debt and debt reduction; expectations regarding increases to dividends and timing thereof; and expectations regarding renewal of our normal course issuer bid, including timing and size thereof.

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; 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 increased dividend payments and the share purchase program from free cash flow as expected and *discussed in this news release; 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: a WTI price of $85.00/bbl, a NYMEX price of $5.00/Mcf, a Bakken crude oil price at par with WTI, a Marcellus natural gas price differential of $0.75/Mcf below NYMEX and a CDN/USD exchange rate of 0.79. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. Current conditions, economic and otherwise, render assumptions, although reasonable when made, subject to greater uncertainty.*

The forward-looking information included in this 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; 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).

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 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.

	Three months ended March 31,	
(US$ millions)	**2022**	**2021**
Cash flow from/(used in) operating activities	$ **196.0**	**$ 28.7**
Asset retirement obligation settlements	8.8	5.6
Changes in non-cash operating working capital	57.1	66.6
Adjusted funds flow	$ **261.9**	**$ 100.9**

“Adjusted net income” 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 adjustment on deferred taxes or goodwill impairment, or valuation allowance on deferred taxes were recorded for the three months ended March 31, 2022 and 2021. The calculation follows:

	Three months ended March 31,	
(US$ millions)	2022	2021
Net income/(loss)	**$ 33.2**	**$ 10.3**
Unrealized non-cash derivative instrument (gain)/loss	133.3	40.4
Asset impairment	—	3.4
Other expense related to investing activities	13.1	—
Unrealized non-cash foreign exchange (gain)/loss	1.2	0.2
Tax effect on above items	(35.0)	(10.4)
Adjusted net income/(loss)	**$ 145.8**	**$ 43.9**

“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. There is no directly comparable related GAAP equivalent for this measure. Adjusted funds flow is reconciled above.

	Three months ended March 31,	
(US$ millions)	2022	2021
Adjusted funds flow	$ 261.9	$ 100.9
Capital spending	(99.0)	(51.8)
Free cash flow	**$ 162.9**	**$ 49.1**

“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. The calculation follows:

	Three months ended March 31,	
(US$ millions)	2022	2021
Net debt	$ 572.3	$ 632.2
Trailing adjusted funds flow	873.5	282.5
Net debt to adjusted funds flow ratio	**0.7x**	**2.2x**

“Reinvestment rate” is used by Enerplus and is useful to investors and securities analysts in analyzing the reinvestment of capital spending by comparing the amount of our capitals spending as compared to adjusted funds flow (as a percentage). There is no directly comparable GAAP measure. The calculation follows:

	Three months ended March 31,	
(US$ millions)	2022	2021
Capital spending	$ 99.0	$ 51.8
Adjusted funds flow	261.9	100.9
Reinvestment rate (%)	**38%**	**51%**

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:

“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.

Electronic copies of Enerplus’ first 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 May 5, 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 months ended March 31, 2022 and 2021 (the "Interim Financial Statements");
- 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. In accordance with U.S. GAAP, crude oil and natural gas sales are presented net of royalties in the Financial Statements. 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 first quarter of 2022 averaged 92,196 BOE/day, a decrease of 10% compared to average production of 102,823 BOE/day in the fourth quarter of 2021, with crude oil and natural gas liquids production decreasing by 14% over the same period. Production decreased in North Dakota as expected, mainly due to production declines as completions activity resumed in March with the first wells coming on-stream at the end of the month. Due to strong operational execution and the continued optimization of our development plan and despite the impacts of the severe winter weather during the second quarter of 2022, we are increasing our annual average production guidance range for 2022 to 96,000 to 101,000 BOE/day, including 58,500 to 62,500 bbls/day in crude oil and natural gas liquids from 95,500 to 100,500 BOE/day, and 58,000 to 62,000 bbls/day in crude oil and natural gas liquids.

Capital spending during the first quarter of 2022 totaled $99.0 million, compared to $81.1 million during the fourth quarter of 2021, with the majority of the spending focused on our U.S. crude oil properties. We are revising our annual capital spending guidance for 2022 to between $400 to $440 million from $370 to $430 million primarily as a result of inflationary pressures due to the high commodity price environment and supply chain tightness, along with increased non-operated activity.

Our realized Bakken crude oil price differential narrowed to average $0.35/bbl below WTI during the first quarter of 2022 compared to $0.88/bbl below WTI during the fourth quarter of 2021. Bakken differentials in North Dakota continued to narrow due to continued improvement in 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, we expect our 2022 realized Bakken oil price to be at par with WTI from a crude oil price differential of $0.50/bbl below WTI, previously.

Our realized Marcellus natural gas price differential narrowed to average $0.01/Mcf above NYMEX in the first quarter of 2022, compared to $1.70/Mcf below NYMEX during the fourth quarter of 2021, due to stronger spot prices in the region along with increased seasonal demand. We are maintaining our annual Marcellus natural gas price differential guidance to average $0.75/Mcf below NYMEX for 2022.

Operating expenses for the first quarter of 2022 increased to $83.2 million or $10.03/BOE, compared to $80.0 million or $8.46/BOE during the fourth quarter of 2021. The increase was primarily due to contracts with price escalators linked to WTI crude oil prices and the Consumer Price Index, and increased well service activity. Due to additional costs incurred to restore production following weather-related downtime during the second quarter of 2022, we are increasing the lower end of our operating expenses guidance to $9.75/BOE, from $9.50/BOE previously.

We reported net income of $33.2 million in the first quarter of 2022 compared to net income of $176.9 million in the fourth quarter of 2021. The decrease in net income recognized in the first quarter of 2022 was primarily due to a $133.0 million unrealized commodity derivative loss compared to an unrealized gain of $68.5 million in the fourth quarter of 2021. The commodity derivative loss is the result of higher commodity prices during the quarter due to the Ukraine/Russia conflict as well as tight global supply.

In the first quarter of 2022 cash flow from operating activities decreased to $196.0 million from $283.5 million in the fourth quarter of 2021. Adjusted funds flow[1] increased to $261.9 million compared to $258.5 million in the fourth quarter of 2021, primarily due to higher realized prices, offset by lower production.

At March 31, 2022, net debt was $572.3 million, comprised of senior notes, the outstanding balance on our sustainability-linked lending bank credit facility (“SLL Bank Credit Facility”) and the revolving bank credit facility totaling $595.0 million, less cash on hand of $22.7 million. Our net debt to adjusted funds flow ratio[1] decreased to 0.7x from 0.9x in the fourth quarter of 2021.

During the first quarter of 2022, a total of $45.1 million was returned to shareholders through share repurchases and dividends.

Subsequent to the quarter, the Board of Directors approved an increase to our 2022 return of capital plan to a minimum of $350 million or 50% of annual free cash flow[1], whichever is greater, through dividends and share repurchases. In connection with this plan, the Board of Directors approved a 30% increase to the quarterly dividend to $0.043 per share, beginning June 2022. The increased dividend is equal to approximately $40 million on an annualized basis. The remaining $310 million or greater of shareholder returns are expected to be delivered through share repurchases, based on current market conditions. We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

RESULTS OF OPERATIONS

Production

Daily production for the first quarter of 2022 averaged 92,196 BOE/day, a decrease of 10% compared to average daily production of 102,823 BOE/day in the fourth quarter of 2021. The decrease is primarily the result of natural production declines as completions activity resumed in March with the first wells coming on-stream in late March. Production in the first quarter of 2022 was also impacted by the sale of our interests in the Sleeping Giant field in Montana and Russian Creek area in North Dakota in the Williston Basin (the “Sleeping Giant/Russian Creek Divestment”), which closed during the fourth quarter of 2021 and was producing approximately 2,400 BOE/day.

For the three months ended March 31, 2022, total production increased by 25% when compared to the same period in 2021, with crude oil and natural gas liquids production increasing by 42% over the same period. The increase in production was primarily due to our acquisition of Bruin E&P HoldCo, LLC (“Bruin” and the “Bruin Acquisition”) and our acquisition of certain assets in the Williston Basin from Hess Bakken Investments II, LLC (the “Dunn County Acquisition”), each of which closed in the first half of 2021, slightly offset by the Sleeping Giant/Russian Creek Divestment in November 2021.

Our crude oil and natural gas liquids weighting for the three months ended March 31, 2022 increased to 61%, from 53% over the same period in 2021.

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

Average daily production volumes for the three months ended March 31, 2022 and 2021 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2022**	**2021**	**% Change**
Light and medium oil (bbls/day)	2,172	2,341	(7%)
Heavy oil (bbls/day)	3,034	3,384	(10%)
Tight oil (bbls/day)	42,428	28,387	49%
Total crude oil (bbls/day)	47,634	34,112	40%
Natural gas liquids (bbls/day)	8,377	5,270	59%
Conventional natural gas (Mcf/day)	7,193	8,733	(18%)
Shale gas (Mcf/day)	209,918	197,216	6%
Total natural gas (Mcf/day)	217,111	205,949	5%
Total daily sales (BOE/day)	92,196	73,707	25%

Despite the impacts of the severe winter weather during the second quarter of 2022, we are increasing our average annual production guidance for 2022 to 96,000 to 101,000 BOE/day, including 58,500 to 62,500 bbls/day in crude oil and natural gas liquids from 95,500 to 100,500 BOE/day, and 58,000 to 62,000 bbls/day in crude oil and natural gas liquids.

Pricing

The prices received for crude oil and natural gas production directly impact our earnings, cash flow from operating activities, adjusted funds flow[1] and financial condition. The following table compares quarterly average benchmark prices, selling prices and differentials:

Pricing (average for the period)	**Q1 2022**	**Q4 2021**	**Q3 2021**	**Q2 2021**	**Q1 2021**
Benchmarks					
WTI crude oil ($/bbl)	$ 94.29	$ 77.19	$ 70.56	$ 66.07	$ 57.84
Brent (ICE) crude oil ($/bbl)	97.38	79.80	73.23	69.02	61.10
NYMEX natural gas – last day ($/Mcf)	4.95	5.83	4.01	2.83	2.69
CDN/US average exchange rate	0.79	0.79	0.79	0.81	0.79
CDN/US period end exchange rate	0.80	0.79	0.79	0.81	0.79
Enerplus selling price(1)					
Crude oil ($/bbl)	$ 91.95	$ 75.21	$ 67.22	$ 62.50	$ 53.24
Natural gas liquids ($/bbl)	37.78	38.77	29.91	18.47	28.55
Natural gas ($/Mcf)	4.62	3.92	3.00	1.96	2.76
Average differentials					
Bakken DAPL – WTI ($/bbl)	$ 0.71	$ 0.53	$ (0.68)	$ (0.40)	$ (2.63)
Brent (ICE) – WTI ($/bbl)	3.09	2.61	2.67	2.95	3.26
MSW Edmonton – WTI ($/bbl)	(2.96)	(3.10)	(4.07)	(3.11)	(5.24)
WCS Hardisty – WTI ($/bbl)	(14.53)	(14.64)	(13.58)	(11.49)	(12.47)
Transco Leidy monthly – NYMEX ($/Mcf)	(0.71)	(0.92)	(1.11)	(1.17)	(0.58)
Transco Z6 Non-New York monthly – NYMEX ($/Mcf)	1.42	(0.16)	(0.73)	(0.72)	0.17
Enerplus realized differentials(1)(2)					
Bakken crude oil – WTI ($/bbl)	$ (0.35)	$ (0.88)	$ (2.26)	$ (2.81)	$ (3.19)
Marcellus natural gas – NYMEX ($/Mcf)	0.01	(1.70)	(0.45)	(0.89)	(0.15)
Canada crude oil – WTI ($/bbl)	(16.31)	(13.82)	(12.87)	(11.65)	(12.88)

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

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

CRUDE OIL AND NATURAL GAS LIQUIDS

During the first quarter of 2022, our realized crude oil sales price averaged $91.95/bbl, an increase of 22% compared to the fourth quarter of 2021 and consistent with the increase in benchmark WTI over the same period. Crude oil prices were impacted by the Ukraine/Russia conflict, the imposition of economic sanctions on Russia and the potential disruption of Russian crude oil production. Both the continued recovery of global crude oil demand due to increasing mobility post-coronavirus pandemic ("COVID-19") and uncertainty over the Organization of the Petroleum Exporting Countries Plus ("OPEC+") nations' ability to materially increase production provided support to global crude oil prices during the quarter.

Bakken crude oil price differentials continued to narrow due to an improvement in the supply and demand balance, excess pipeline capacity in the region, and strong prices for crude oil delivered to the U.S. Gulf Coast. Our realized Bakken crude oil price differential averaged $0.35/bbl below WTI during the first quarter of 2022, compared to $0.88/bbl below WTI during the fourth quarter of 2021. Given stronger year-to-date realizations, we expect our 2022 realized Bakken oil price to be at par with WTI from a crude oil price differential of $0.50/bbl below WTI, previously.

Our realized sales price for natural gas liquids averaged $37.78/bbl during the first quarter of 2022, a decrease of 3% compared to the fourth quarter of 2021.

NATURAL GAS

Our realized natural gas sales price averaged $4.62/Mcf during the first quarter of 2022, an increase of 18% compared to the fourth quarter of 2021, while the NYMEX benchmark price decreased by 15% over the same period. The difference in price realization versus the benchmark was due to the majority of our natural gas sales during the quarter being made in the daily spot markets, which outperformed the benchmark NYMEX last day pricing.

Our realized Marcellus sales price differential narrowed considerably compared to the previous quarter, as expected, due to seasonal demand and stronger spot prices in the region. Our differential in the quarter averaged $0.01/Mcf above NYMEX compared to $1.70/Mcf below NYMEX in the fourth quarter of 2021. A significant portion of our production receives prices reflecting market conditions south of New York at Transco Zone 6 Non-New York, which averaged $1.42/Mcf over NYMEX in the first quarter of 2022. We expect Marcellus differentials to widen for the remainder of 2022, due to the seasonal impact on natural gas prices in the region. Based on this, we are maintaining our Marcellus natural gas sales price differential guidance of $0.75/Mcf below NYMEX for 2022.

FOREIGN EXCHANGE

Fluctuations in the U.S. dollar will impact the amount of 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 weaker in the first quarter of 2022 at 0.80 CDN/US, compared to 0.79 CDN/US at December 31, 2021. The average exchange rate during the first quarter of 2022 was consistent compared to the same period in 2021, averaging 0.79 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 expenditures.

At May 4, 2022, we have commodity derivative contracts in place for approximately 21,100 bbls/day of our expected crude oil production for the remainder of 2022 and 7,000 bbls/day during 2023. Our crude oil contracts are predominately three way collars. The three way collars provide us with exposure to upward price movement; however, the sold put effectively limits the amount of downside protection we have to the difference between the strike price of the purchased and sold puts. For natural gas, we have contracts in place for 100,000 Mcf/day of natural gas for the period of April 1, 2022 to October 31, 2022.

The following is a summary of our financial contracts in place at May 4, 2022:

	WTI Crude Oil ($/bbl) (1)(2)(3)				NYMEX Natural Gas ($/Mcf)(2)
	Apr 1, 2022 – June 30, 2022	**Apr 1, 2022 – Dec 31, 2022**	**Jan 1, 2023 – June 30, 2023**	**Jan 1, 2023 – Dec 31, 2023**	**Apr 1, 2022 – Oct 31, 2022**
Swaps					
Volume (Mcf/day)	–	–	–	–	40,000
Sold Swaps	–	–	–	–	$ 3.40
Collars					
Volume (Mcf/day)	–	–	–	–	60,000
Volume (bbls/day)	12,500	17,000	10,000	2,000	–
Sold Puts	$ 58.00	$ 40.00	$ 60.00	–	–
Purchased Puts	$ 75.00	$ 50.00	$ 76.50	$ 5.00	$ 3.77
Sold Calls	$ 87.63	$ 57.91	$ 107.38	$ 75.00	$ 4.50

(1) The total average deferred premium spent on our outstanding crude oil contracts is $1.50/bbl from April 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 March 31, 2022, the remaining liability was $16.3 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.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	**Three months ended March 31,**	
($ millions)	**2022**	**2021**
Realized gains/(losses):		
Crude oil	$ (72.7)	$ (16.0)
Natural gas	(0.4)	0.6
Total realized gains/(losses)	$ (73.1)	$ (15.4)
Unrealized gains/(losses):		
Crude oil	$ (95.7)	$ (41.9)
Natural gas	(38.0)	1.0
Total unrealized gains/(losses)	$ (133.7)	$ (40.9)
Total gains/(losses)	$ (206.8)	$ (56.3)

	Three months ended March 31,	
(Per BOE)	**2022**	**2021**
Total realized gains/(losses)	$ (8.81)	$ (2.32)
Total unrealized gains/(losses)	(16.11)	(6.16)
Total commodity derivative instruments gains/(losses)	$ (24.92)	$ (8.48)

During the three months ended March 31, 2022, Enerplus realized losses of $72.7 million on our crude oil contracts compared to $16.0 million for the same period in 2021. In the three months ended March 31, 2022, realized losses of $0.4 million were recorded on our natural gas contracts compared to a realized gain of $0.6 million for the same period in 2021. Cash losses recorded during the three months ended March 31, 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 recorded as either an unrealized charge or gain to earnings. At March 31, 2022, the fair value of our crude oil and natural gas contracts was in a net liability position of $270.3 million (December 31, 2021 – $143.7 million). For the three months ended March 31, 2022, the change in the fair value of our crude oil contracts resulted in an unrealized loss of $95.7 million, compared to an unrealized loss of $41.9 million during the same period in 2021. For the three months ended March 31, 2022, we recorded an unrealized loss on our natural gas contracts of $38.0 million, compared to an unrealized gain of $1.0 million during the same period in 2021.

Crude Oil and Natural Gas Sales

($ millions, except per BOE amounts)	Three months ended March 31, 2022	2021
Crude oil and natural gas sales	$ 513.2	$ 228.4
Per BOE	$ 61.84	$ 34.43

Crude oil and natural gas sales for the three months ended March 31, 2022 were $513.2 million or $61.84/BOE, an increase from $228.4 million or $34.43/BOE for the same period in 2021. The increase in revenue was primarily due to additional production from the Bruin and Dunn County acquisitions completed during the first half of 2021 as well as higher commodity prices. See Note 11 to the Interim Financial Statements for further details.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended March 31, 2022	2021
Operating expenses	$ 83.2	$ 51.2
Per BOE	$ 10.03	$ 7.71

For the three months ended March 31, 2022, operating expenses were $83.2 million or $10.03/BOE, compared to $51.2 million or $7.71/BOE for the same period in 2021. The increase was primarily due to higher U.S. crude oil weighting in our production mix as a result of the Bruin and Dunn County acquisitions and increased liquids weighting to 61% compared to 53% for the same period in 2021 with higher associated operating costs. In addition, operating expenses increased due to contracts with price escalators linked to WTI crude oil prices and the Consumer Price Index, and increased well service activity.

Due to additional costs incurred to restore production following weather-related downtime during the second quarter of 2022, we are revising our expected operating expenses guidance for 2022 to average between $9.75/BOE to $10.50/BOE from $9.50/BOE to $10.50/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended March 31, 2022	2021
Transportation costs	$ 35.8	$ 25.9
Per BOE	$ 4.32	$ 3.91

For the three months ended March 31, 2022, transportation costs were $35.8 million or $4.32/BOE, compared to $25.9 million or $3.91/BOE for the same period in 2021. The increase in transportation costs was primarily a result of increased U.S. production with higher associated transportation costs and additional firm transportation commitments on the Dakota Access Pipeline ("DAPL"), compared to the same period in 2021 as a result of the Bruin Acquisition and participation in the DAPL expansion in August 2021.

We continue to expect transportation costs of $4.15/BOE in 2022.

Production Taxes

($ millions, except per BOE amounts)	Three months ended March 31, 2022	2021
Production taxes	$ 35.4	$ 13.8
Per BOE	$ 4.26	$ 2.09
Production taxes (% of crude oil and natural gas sales)	6.9%	6.1%

Production taxes include state production taxes, Pennsylvania impact fees and Canadian freehold mineral taxes and production surcharges.

Production taxes for the three months ended March 31, 2022 were $35.4 million, compared to $13.8 million for the same period in 2021. The increase was due to higher realized prices, compared to the same period 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 March 31, 2022		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	64,036 BOE/day	168,959 Mcfe/day	92,196 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 76.05	$ 4.92	$ 61.84
Operating expenses	(13.78)	(0.25)	(10.03)
Transportation costs	(3.86)	(0.89)	(4.32)
Production taxes	(6.01)	(0.05)	(4.26)
Netback before impact of commodity derivative contracts	$ 52.40	$ 3.73	$ 43.23
Realized hedging gains/(losses)	(12.61)	(0.03)	(8.81)
Netback after impact of commodity derivative contracts	$ 39.79	$ 3.70	$ 34.42
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 302.0	$ 56.8	$ 358.8
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 229.3	$ 56.4	$ 285.7

	Three months ended March 31, 2021		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	44,858 BOE/day	173,090 Mcfe/day	73,707 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 46.41	$ 2.63	$ 34.43
Operating expenses	(12.02)	(0.17)	(7.71)
Transportation costs	(3.00)	(0.89)	(3.91)
Production taxes	(3.34)	(0.02)	(2.09)
Netback before impact of commodity derivative contracts	$ 28.05	$ 1.55	$ 20.72
Realized hedging gains/(losses)	(3.96)	0.04	(2.32)
Netback after impact of commodity derivative contracts	$ 24.09	$ 1.59	$ 18.40
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 113.2	$ 24.3	$ 137.5
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 97.3	$ 24.8	$ 122.1

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

Total netbacks before and after hedging for the three months ended March 31, 2022 were higher compared to the same period in 2021, primarily due to higher production and higher realized prices.

For the three months ended March 31, 2022, crude oil properties accounted for 84% of total netback before hedging, compared to 82% during the same period in 2021.

G&A Expenses

Total G&A expenses include cash 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.

	Three months ended March 31,	
($ millions)	2022	2021
Cash:		
G&A expense	$ 11.2	$ 10.4
Share-based compensation expense	2.1	2.2
Non-Cash:		
Share-based compensation expense	4.8	0.8
Equity swap gain	(0.4)	(0.5)
G&A recovery	(0.1)	(0.1)
Total G&A expenses	$ 17.6	$ 12.8

	Three months ended March 31,	
(Per BOE)	2022	2021
Cash:		
G&A expense	$ 1.35	$ 1.57
Share-based compensation expense	0.25	0.32
Non-Cash:		
Share-based compensation expense	0.58	0.13
Equity swap gain	(0.05)	(0.07)
G&A recovery	(0.01)	(0.01)
Total G&A expenses	$ 2.12	$ 1.94

Cash G&A expenses for the three months ended March 31, 2022 were $11.2 million or $1.35/BOE, compared to $10.4 million or $1.57/BOE for the same period in 2021. Total cash G&A expenses increased slightly 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 was $2.1 million, or $0.25/BOE, for the first three months ended March 31, 2022, compared to $2.2 million, or $0.32/BOE, for the same period in 2021. The increase was due to the impact of the higher share price during 2022. Equity settled non-cash SBC was $4.8 million, or $0.58/BOE, for the three months ended March 31, 2022, compared to $0.8 million, or $0.13/BOE, for the same period in 2021. Performance Share Units ("PSUs"), as one of the equity settled LTI plans, are impacted by performance multipliers. For the three months ended March 31, 2022, the multipliers were higher, resulting in an increase in expense compared to the same period in 2021.

Enerplus has hedged a portion of the outstanding cash settled units under our LTI plans. In the first quarter of 2022, we recorded a market-to-market gain of $0.4 million on these contracts, compared to a gain of $0.5 million for the same period in 2021, as a result of the higher share price.

We continue to expect cash G&A expenses of $1.25/BOE for 2022.

Interest Expense

For the three months ended March 31, 2022, we recorded a total interest expense of $6.1 million, compared to $5.6 million for the same period in 2021. The increase was primarily due to higher debt levels incurred to fund the Buin and Dunn County acquisitions, partially offset by the final repayment of our 2009 senior notes and scheduled repayment of our 2012 senior notes, which carry higher interest rates than our SLL Bank Credit Facility and revolving bank credit facility (together referred to as the "Bank Credit Facilities").

At March 31, 2022, approximately 51% of Enerplus' debt was based on fixed interest rates and 49% on floating interest rates (December 31, 2021 – 43% fixed and 57% floating), with weighted average interest rates of 4.2% and 1.9%, respectively. See Note 8 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended March 31, 2022		2021	
Realized:				
Foreign exchange (gain)/loss	$	(0.3)	$	(0.5)
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company		—		0.4
Unrealized:				
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company		1.2		0.1
Total foreign exchange (gain)/loss	$	0.9	$	—
CDN/US average exchange rate		0.79		0.79
CDN/US period end exchange rate		0.80		0.79

For the three months ended March 31, 2022, Enerplus recorded a foreign exchange loss of $0.9 million, compared to no gain or loss recorded for the same period 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 March 31, 2022, $303.8 million of senior notes outstanding and $293.0 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 months ended March 31, 2022, Other Comprehensive Income/(Loss) included an unrealized gain of $5.4 million on our U.S. dollar denominated senior notes and Bank Credit Facilities (2021 – $5.7 million gain).

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

($ millions)	Three months ended March 31, 2022		2021	
Capital spending[(1)]	$	99.0	$	51.8
Office capital		0.3		1.3
Sub-total		99.3		53.1
Bruin Acquisition	$	—	$	494.7
Property and land acquisitions		1.9		2.4
Property divestments		(6.6)		(4.0)
Sub-total		(4.7)		493.1
Total	$	94.6	$	546.2

(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 months ended March 31, 2022 totaled $99.0 million, compared to $51.8 million for the same period in 2021. The increase is mainly due to increased capital activity on our North Dakota properties. Capital spending during the first quarter of 2022 included $82.1 million on our U.S. crude oil properties and $14.5 million on our Marcellus natural gas assets.

During the first quarter of 2021, we completed the Bruin Acquisition for total cash consideration of $465.0 million or $420.2 million after purchase price adjustments with $494.7 million allocated to PP&E, excluding the assumed asset retirement obligation. Property divestments for the three months ended March 31, 2022 were $6.6 million compared to $4.0 million for the same period in 2021.

We are increasing our annual capital spending guidance for 2022 to between $400 to $440 million from $370 to $430 million primarily as a result of inflationary pressures due to the high commodity price environment and supply chain tightness, along with increased non-operated activity and associated costs.

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

($ millions, except per BOE amounts)	Three months ended March 31, 2022		2021	
DD&A expense	$	66.7	$	36.7
Per BOE	$	8.04	$	5.53

DD&A related to PP&E is recognized using the unit of production method based on proved reserves. For the three months ended March 31, 2022, Enerplus recorded DD&A expense of $66.7 million, compared to $36.7 million for the same period in 2021. DD&A expense increased as a result of higher overall production volumes and the net impact of acquisitions, divestments and previous PP&E impairments.

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 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 first quarter of 2022. There were no impairments for the three months ended March 31, 2022. For the three months ended March 31, 2021, we recorded a PP&E impairment of $3.4 million 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 $144.6 million at March 31, 2022, compared to $132.8 million at December 31, 2021.

For the three months ended March 31, 2022, ARO settlements were $8.8 million, compared to $5.6 million during the same period in 2021.

Enerplus benefited from provincial government assistance to support the cleanup 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 months ended March 31, 2022, Enerplus benefitted from $0.4 million in government assistance (2021 – $1.3 million). 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 March 31, 2022, our total lease liability was $27.2 million (December 31, 2021 - $28.9 million). In addition, ROU assets of $24.5 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 March 31,	
($ millions)	2022	2021
Current tax expense/(recovery)	$ 5.0	$ —
Deferred tax expense/(recovery)	9.8	8.7
Total tax expense/(recovery)	$ 14.8	$ 8.7

For the three months ended March 31, 2022, we recorded a current tax expense of $5.0 million compared to nil tax expense recorded for the same period in 2021. Current tax consists of U.S. federal and state tax as a result of higher net income in 2022 as we could potentially utilize the full amount of our net operating loss carryforwards in 2022. Many factors influence taxable income including future commodity prices, production levels, development activities, capital spending, and overall profitability. As a result of the higher commodity prices, we are updating our current tax guidance from $10.0 million to $20.0 million – $30.0 million (2% – 3% of adjusted funds flow before tax) for 2022 assuming WTI of $85.00/bbl and NYMEX of $5.00/Mcf.

For the three months ended March 31, 2022, we recorded a deferred income tax expense of $9.8 million, compared to an expense of $8.7 million for the same period in 2021.

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 three months ended March 31, 2022, no valuation allowance was recorded against our U.S. and 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 $374.2 million at March 31, 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 March 31, 2022, our senior debt to adjusted EBITDA ratio was 0.7x and our net debt to adjusted funds flow ratio[1] was 0.7x. Although a non-GAAP 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. Refer to the definitions and footnotes below.

Net debt at March 31, 2022 decreased to $572.3 million, compared to $640.4 million at December 31, 2021. Total debt was comprised of our senior notes, and Bank Credit Facilities, totaling $595.0 million, less cash on hand of $22.7 million. During the quarter, 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 March 31, 2022 through our Bank Credit Facilities, we had total credit capacity of $1.3 billion, of which $293.0 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 38% for the three months ended March 31, 2022 compared to 51% for the same period in 2021. We are committed to free cash flow generation and are targeting a long-term capital spending reinvestment rate[1] of less than 75% of annual adjusted funds flow[1].

During the first quarter of 2022, a total of $45.1 million was returned to shareholders through share repurchases and dividends, compared to $5.6 million for the same period in 2021. A total of 3,134,700 common shares were repurchased and cancelled under the Normal Course Issuer Bid ("NCIB") at an average price of $11.87 per share, for total consideration of $37.2 million. We did not have a NCIB in place during the three months ended March 31, 2021. Subsequent to March 31, 2022 and up to and including May 4, 2022, we repurchased 1,494,996 common shares under the NCIB at an average price of $12.61 per share, for total consideration of $18.9 million.

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

Subsequent to the quarter, the Board of Directors approved an increase to our 2022 return of capital plan to a minimum of $350 million or 50% of annual free cash flow[1], whichever is greater, through dividends and share repurchases. In connection with this plan, the Board of Directors approved a 30% increase to the quarterly dividend to $0.043 per share, beginning June 2022. The increased dividend is equal to approximately $40 million on an annualized basis. The remaining $310 million or greater of shareholder returns are expected to be delivered through share repurchases. We plan to repurchase the remaining 8.0 million shares under the NCIB by the end of July and renew the NCIB in August for an additional 10% of the public float (within meaning under the Toronto Stock Exchange ("TSX") rules). We expect to fund the dividend and share repurchases through the free cash flow generated by the business.

At March 31, 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 March 31, 2022:

Covenant Description		March 31, 2022
Bank Credit Facilities:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	0.7x
Total debt to adjusted EBITDA	4.0x	0.7x
Total debt to capitalization	55%	31%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.0x - 3.5x	0.7x
Senior debt to consolidated present value of total proved reserves(2)	60%	15%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	32.3x

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 March 31, 2022 was $272.6 million and $899.8 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 March 31,	
($ millions, except per share amounts)	2022	2021
Dividends(1)	$ 7.9	$ 5.6
Per weighted average share (Basic)	$ 0.033	$ 0.024

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

During the three months ended March 31, 2022, we declared total dividends of $7.9 million or $0.033 per share, compared to $5.6 million or $0.024 per share for the same period in 2021. The aggregate amount of dividends paid to shareholders has increased compared to the same period in 2021 due to an overall 37% increase of our quarterly dividend since the first quarter of 2021, as well as an increase in common shares outstanding resulting from the Bruin equity financing in the first quarter of 2021.

Subsequent to the quarter, the Board of Directors approved a 30% increase to the quarterly dividend to $0.043 per share to be paid beginning in June 2022. We expect to fund the dividend through the free cash flow[1] generated by the business. The dividend is a part of our strategy to return capital to shareholders. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Three months ended March 31,	
	2022	2021
Share capital ($ millions)	$ 3,070.7	$ 3,222.8
Common shares outstanding (thousands)	241,957	256,751
Weighted average shares outstanding – basic (thousands)	242,787	244,066
Weighted average shares outstanding – diluted (thousands)	249,337	246,898

For the three months ended March 31, 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 amount of $11.6 million (2021 – $3.6 million).

On August 12, 2021, we received approval from the TSX to commence a NCIB to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. During the three months ended March 31, 2022, 3,134,700 common shares were repurchased and cancelled under the NCIB at an average price of $11.87 per share, for total consideration of $37.2 million. Of the amount paid, $31.3 million was charged to share capital and $5.9 million was credited to accumulated deficit. We did not have an NCIB in place during the three months ended March 31, 2021. At March 31, 2022, 9,533,390 common shares were available for repurchase under the current NCIB.

Subsequent to March 31, 2022, and up to and including May 4, 2022, we repurchased 1,494,996 common shares under the NCIB at an average price of $12.61 per common share, for total consideration of $18.9 million.

At May 4, 2022, we had 240,462,683 common shares outstanding. In addition, an aggregate of 10,278,694 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 March 31, 2022			Three months ended March 31, 2021		
($ millions, except per unit amounts)	U.S.	Canada	Total	U.S.	Canada	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	42,428	5,206	47,634	28,387	5,725	34,112
Natural gas liquids (bbls/day)	8,080	297	8,377	4,885	385	5,270
Natural gas (Mcf/day)	209,696	7,415	217,111	196,732	9,217	205,949
Total average daily production (BOE/day)	85,457	6,739	92,196	66,061	7,646	73,707
Pricing[1]						
Crude oil (per bbl)	$ 93.66	$ 75.99	$ 91.95	$ 54.91	$ 44.52	$ 53.24
Natural gas liquids (per bbl)	37.25	51.48	37.78	28.42	31.06	28.55
Natural gas (per Mcf)	4.64	3.80	4.62	2.72	3.13	2.76
Property, Plant and Equipment						
Capital and office expenditures	$ 96.6	$ 2.7	$ 99.3	$ 49.3	$ 3.8	$ 53.1
Acquisitions, including property and land	1.3	0.6	1.9	496.3	0.8	497.1
Property divestments	(6.6)	—	(6.6)	—	(4.0)	(4.0)
Netback Before Impact of Commodity Derivative Contracts[2]						
Crude oil and natural gas sales	$ 472.3	$ 40.9	$ 513.2	$ 200.9	$ 27.5	$ 228.4
Operating expenses	(71.6)	(11.6)	(83.2)	(41.7)	(9.5)	(51.2)
Transportation cost	(34.6)	(1.2)	(35.8)	(24.3)	(1.6)	(25.9)
Production taxes	(34.8)	(0.6)	(35.4)	(13.4)	(0.4)	(13.8)
Netback before impact of commodity derivative contracts	$ 331.3	$ 27.5	$ 358.8	$ 121.5	$ 16.0	$ 137.5
Other Expenses						
Commodity derivative instruments loss	$ —	$ 206.8	$ 206.8	$ —	$ 56.3	$ 56.3
Asset impairment	—	—	—	3.4	—	3.4
General and administrative expense[3]	7.6	10.0	17.6	7.6	5.2	12.8
Current income tax expense	5.0	—	5.0	—	—	—

(1) Before transportation costs and the effects of commodity derivative instruments.
(2) This financial measure is a non-GAAP financial measure. See "Non-GAAP and Other Financial 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				
First Quarter	$ 513.2	$ 33.2	$ 0.14	$ 0.13
Total 2022	$ 513.2	$ 33.2	$ 0.14	$ 0.13
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 $513.2 million during the first quarter of 2022, compared to $499.7 million during the fourth quarter of 2021. The increase in crude oil and natural gas sales was a result of improved realized pricing during the first quarter of 2022, when compared to the fourth quarter of 2021. We reported net income of $33.2 million during the first quarter of 2022 compared to net income of $176.9 million during the fourth quarter of 2021. The decrease was primarily due to a $206.8 million loss recorded on commodity derivative instruments as a result of higher commodity prices.

Crude oil and natural gas sales increased in 2021 compared to 2020 due to higher production from the Bruin and 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.

RISK FACTORS AND RISK MANAGEMENT

Risks relating to the Impact of the Ukraine and Russia conflict

The current conflict between Ukraine and Russia and the international response has, and may continue to have, potential wide-ranging consequences for global market volatility and economic conditions, including oil and gas prices. Certain countries including Canada, the United States, Australia and certain European countries have imposed strict financial and trade sanctions against Russia, which may have continued far-reaching effects on the global economy, energy and commodity prices and food security and crop nutrient supply and prices. The short-, medium- and long-term implications of the conflict in Ukraine are difficult to predict with any degree of certainty at this time. Depending on the extent, duration, and severity of the conflict, it may have the effect of heightening many of the other risks described in our Annual MD&A and our Annual Information Form for the year ended December 31, 2021, including, without limitation, risks relating to global market volatility and economic conditions; cybersecurity threats; oil and gas prices; inflationary pressures, interest rates and costs of capital; and supply chains and cost-effective and timely transportation.

RECENT ACCOUNTING STANDARDS

We have not early adopted any accounting standard, interpretation or amendment that has been issued but is not yet effective. Our significant accounting policies remain unchanged from December 31, 2021.

2022 GUIDANCE[1]

We are revising our annual capital spending guidance for 2022 to between $400 to $440 million, from a range of $370 to $430 million.

We are revising our average annual production guidance for 2022 to 96,000 to 101,000 BOE/day, including 58,500 to 62,500 bbls/day in crude oil and natural gas liquids from 95,500 to 100,500 BOE/day including 58,000 to 62,000 bbls/day in crude oil and natural gas liquids.

We are revising our expected operating expenses guidance for 2022 to average between $9.75/BOE to $10.50/BOE from $9.50/BOE to $10.50/BOE.

In 2022, we expect our realized Bakken oil price to be at par with WTI, compared to $0.50/bbl below WTI, previously.

As a result of the higher commodity price environment, we are increasing our current tax guidance from $10 million to $20 – $30 million (2% – 3% of adjusted funds flow before tax) for 2022 assuming WTI of $85.00/bbl and NYMEX of $5.00/Mcf.

Summary of 2022 Annual Expectations	Target Annual Results
Capital spending ($ millions)	$400 - $440 (from $370 - $430)
Average annual production (BOE/day)	96,000 - 101,000 (from 95,500 - 100,500)
Average annual crude oil and natural gas liquids production (bbls/day)	58,500 - 62,500 (from 58,000 - 62,000)
Average production tax rate (% of net sales, before transportation)	7%
Operating expenses (per BOE)	$9.75 - $10.50 (from $9.50 - $10.50)
Transportation costs (per BOE)	$4.15
Cash G&A expenses (per BOE)	$1.25
Current tax expense	$20 - $30 million (2% - 3% of adjusted funds flow before tax) (from $10 million)

Differential/Basis Outlook[2]	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	$0/bbl (from $(0.50)/bbl)
Average Marcellus natural gas differential (compared to NYMEX natural gas)	$(0.75)/Mcf

(1) Guidance is based on the continued operation of DAPL and has not been adjusted to reflect the potential divestment of our Canadian assets as announced on February 2, 2022.
(2) Excludes transportation costs.

NON-GAAP MEASURES

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

These non-GAAP financial measures and non-GAAP ratios do not have standardized meanings or definitions as prescribed by U.S. GAAP and may not be comparable with the calculation of similar financial measures by other entities. For each measure, we have 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 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.

	Three months ended March 31,	
($ millions)	2022	2021
Cash flow from/(used in) operating activities	**$ 196.0**	**$ 28.7**
Asset retirement obligation settlements	8.8	5.6
Changes in non-cash operating working capital	57.1	66.6
Adjusted funds flow	**$ 261.9**	**$ 100.9**

"Adjusted net income" 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 adjustment on deferred taxes or goodwill impairment, or valuation allowance on deferred taxes were recorded for the three months ended March 31, 2022 and 2021. The calculation follows:

	Three months ended March 31,	
($ millions)	2022	2021
Net income/(loss)	**$ 33.2**	**$ 10.3**
Unrealized non-cash derivative instrument (gain)/loss	133.3	40.4
Asset impairment	—	3.4
Other expense related to investing activities	13.1	—
Unrealized non-cash foreign exchange (gain)/loss	1.2	0.2
Tax effect on above items	(35.0)	(10.4)
Adjusted net income/(loss)	**$ 145.8**	**$ 43.9**

"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. There is no directly comparable related GAAP equivalent for this measure. Adjusted funds flow is reconciled above.

	Three months ended March 31,	
($ millions)	2022	2021
Adjusted funds flow	$ 261.9	$ 100.9
Capital spending	(99.0)	(51.8)
Free cash flow	**$ 162.9**	**$ 49.1**

“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. The calculation follows:

	Three months ended March 31,	
($ millions)	**2022**	**2021**
Net debt	$ 572.3	$ 632.2
Trailing adjusted funds flow	873.5	282.5
Net debt to adjusted funds flow ratio	**0.7x**	**2.2x**

“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 as follows:

	Three months ended March 31,	
($ millions)	**2022**	**2021**
Crude oil and natural gas sales	$ 513.2	$ 228.4
Less:		
Operating expenses	(83.2)	(51.2)
Transportation costs	(35.8)	(25.9)
Production taxes	(35.4)	(13.8)
Netback before impact of commodity derivative contracts	**$ 358.8**	**$ 137.5**
Net realized gain/(loss) on derivative instruments	(73.1)	(15.4)
Netback after impact of commodity derivative contracts	**$ 285.7**	**$ 122.1**

“Reinvestment rate” is used by Enerplus and is useful to investors and securities analysts in analyzing the reinvestment of capital spending by comparing the amount of our capitals spending as compared to adjusted funds flow (as a percentage). There is no directly comparable GAAP measure. The calculation follows:

	Three months ended March 31,	
($ millions)	**2022**	**2021**
Capital spending	$ 99.0	$ 51.8
Adjusted funds flow	261.9	100.9
Reinvestment rate (%)	**38%**	**51%**

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:

“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.

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.

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 March 31, 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 January 1, 2022 and ended March 31, 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: expected production volumes in 2022 and 2022 production guidance; 2022 capital spending guidance and expected capital spending levels in 2022; 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; 2022 average production volumes and the anticipated production mix; 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 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, tax pools and the time at which cash taxes may be paid; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending, 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, including the divestment process for our Canadian assets in 2022 and the completion and timing thereof; and expectations regarding renewal of our NCIB, including timing and size thereof.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; 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; 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 $85.00/bbl, a NYMEX price of $5.00/Mcf, a Bakken crude oil price at par with WTI, a Marcellus natural gas price differential of $0.75/Mcf below NYMEX and a CDN/USD exchange rate of 0.79. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. Current conditions, economic and otherwise, render assumptions, although reasonable when made, subject to greater uncertainty.*

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued instability, or further deterioration, in global economic and market environment, including from COVID-19, 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).

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	March 31, 2022	December 31, 2021
Assets			
Current assets			
Cash and cash equivalents		$ 22,731	$ 61,348
Accounts receivable	3	282,644	227,988
Other current assets		9,118	10,956
Derivative financial assets	16	—	5,668
		314,493	305,960
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	4, 5	1,303,239	1,253,505
Other capital assets	4	13,234	13,887
Property, plant and equipment		1,316,473	1,267,392
Other long-term assets		7,526	9,756
Right-of-use assets	10	24,492	26,118
Deferred income tax asset	14	374,238	380,858
Total Assets		$ 2,037,222	$ 1,990,084
Liabilities			
Current liabilities			
Accounts payable	7	$ 404,192	$ 367,008
Current portion of long-term debt	8	100,600	100,600
Derivative financial liabilities	16	257,038	143,200
Current portion of lease liabilities	10	10,852	10,618
		772,682	621,426
Long-term debt	8	494,402	601,171
Asset retirement obligation	9	144,591	132,814
Derivative financial liabilities	16	13,866	7,098
Lease liabilities	10	16,310	18,265
		669,169	759,348
Total Liabilities		1,441,851	1,380,774
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: March 31, 2022 – 242 million shares			
December 31, 2021 – 244 million shares	15	3,070,678	3,094,061
Paid-in capital		36,110	50,881
Accumulated deficit		(2,218,865)	(2,238,325)
Accumulated other comprehensive loss		(292,552)	(297,307)
		595,371	609,310
Total Liabilities & Shareholders' Equity		$ 2,037,222	$ 1,990,084

Subsequent Event	15

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 March 31, 2022	2021
Revenues			
Crude oil and natural gas sales	11	$ 513,152	$ 228,390
Commodity derivative instruments loss	16	(206,810)	(56,263)
		306,342	172,127
Expenses			
Operating		83,244	51,162
Transportation		35,807	25,927
Production taxes		35,355	13,845
General and administrative	12	17,581	12,841
Depletion, depreciation and accretion		66,691	36,698
Asset impairment	5	—	3,420
Interest		6,055	5,633
Foreign exchange (gain)/loss	13	887	(24)
Transaction costs and other expense/(income)	9	12,697	3,619
		258,317	153,121
Income/(Loss) before taxes		48,025	19,006
Current income tax expense	14	5,000	—
Deferred income tax expense/(recovery)	14	9,782	8,657
Net Income/(Loss)		$ 33,243	$ 10,349
Other Comprehensive Income/(Loss)			
Unrealized gain/(loss) on foreign currency translation		(620)	(807)
Foreign exchange gain/(loss) on net investment hedge, net of tax	16	5,375	5,714
Total Comprehensive Income/(Loss)		$ 37,998	$ 15,256
Net Income/(Loss) per share			
Basic	15	$ 0.14	$ 0.04
Diluted	15	$ 0.13	$ 0.04

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 March 31, 2022	2021
Share Capital		
Balance, beginning of period	$ 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	(31,342)	—
Share-based compensation – treasury settled	7,959	9,402
Balance, end of period	$ 3,070,678	$ 3,222,747
Paid-in Capital		
Balance, beginning of period	$ 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	4,755	1,654
Balance, end of period	$ 36,110	$ 38,083
Accumulated Deficit		
Balance, beginning of period	$ (2,238,325)	$ (2,447,735)
Purchase of common shares under Normal Course Issuer Bid	(5,865)	—
Net income/(loss)	33,243	10,349
Dividends declared(1)	(7,918)	(5,634)
Balance, end of period	$ (2,218,865)	$ (2,443,020)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of period	$ (297,307)	$ (294,511)
Unrealized gain/(loss) on foreign currency translation	(620)	(807)
Foreign exchange gain/(loss) on net investment hedge, net of tax	5,375	5,714
Balance, end of period	$ (292,552)	$ (289,604)
Total Shareholders' Equity	$ 595,371	$ 528,206

(1) For the three months ended March 31, 2022, dividends declared were $0.033 per share (2021 – $0.024 per share).

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 March 31, 2022	2021
Operating Activities			
Net income/(loss)		$ 33,243	$ 10,349
Non-cash items add/(deduct):			
Depletion, depreciation and accretion		66,691	36,698
Asset impairment	5	—	3,420
Changes in fair value of derivative instruments	16	133,332	40,358
Deferred income tax expense/(recovery)	14	9,782	8,657
Foreign exchange (gain)/loss on debt and working capital	13	1,171	157
Share-based compensation and general and administrative	12,15	4,660	802
Other expense	9	12,653	—
Amortization of debt issuance costs	8	353	57
Translation of U.S. dollar cash held in parent company	13	10	356
Asset retirement obligation settlements	9	(8,795)	(5,625)
Changes in non-cash operating working capital	17	(57,108)	(66,567)
Cash flow from/(used in) operating activities		195,992	28,662
Financing Activities			
Proceeds from/(repayment of) bank credit facilities	8	(104,409)	400,000
Debt issuance costs	8	—	(2,834)
Proceeds from the issuance of shares	15	—	98,339
Purchase of common shares under Normal Course Issuer Bid	15	(37,207)	—
Share-based compensation – tax withholdings settled in cash	15	(11,567)	(3,551)
Dividends	15,17	(7,918)	(5,337)
Cash flow from/(used in) financing activities		(161,101)	486,617
Investing Activities			
Capital and office expenditures	17	(75,027)	(40,345)
Bruin acquisition	6	—	(418,241)
Property and land acquisitions		(1,941)	(2,471)
Property divestments		6,581	4,010
Cash flow from/(used in) investing activities		(70,387)	(457,047)
Effect of exchange rate changes on cash & cash equivalents		(3,121)	2,289
Change in cash and cash equivalents		(38,617)	60,521
Cash and cash equivalents, beginning of period		61,348	89,945
Cash and cash equivalents, end of period		$ 22,731	$ 150,466

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 months ended March 31, 2022 and the 2021 comparative periods. 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)	March 31, 2022	December 31, 2021
Accrued revenue	$ 267,721	$ 208,160
Accounts receivable – trade	18,960	23,697
Allowance for doubtful accounts	(4,037)	(3,869)
Total accounts receivable, net of allowance for doubtful accounts	$ 282,644	$ 227,988

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

At March 31, 2022 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Crude oil and natural gas properties[(1)]	$ 13,255,443	$ (11,952,204)	$ 1,303,239
Other capital assets	104,511	(91,277)	13,234
Total PP&E	$ 13,359,954	$ (12,043,481)	$ 1,316,473

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 months ended March 31, 2022 (2021 – Canadian cost centre: $3.4 million). 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.

In 2021, Enerplus requested and received a temporary exemption from the Securities Exchange Commission to exclude the properties acquired from Bruin in the full cost ceiling test. This exemption was used in Enerplus' March 31, 2021 ceiling test.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from March 31, 2021 through March 31, 2022:

Period	WTI Crude Oil $/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas $/Mcf	Exchange Rate CDN$/US$
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
Q1 2021	39.95	46.10	2.18	0.75

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 after March 31, 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)	March 31, 2022	December 31, 2021
Accrued payables	$ 163,259	$ 106,222
Accounts payable – trade	240,933	260,786
Total accounts payable	$ 404,192	$ 367,008

8) DEBT

($ thousands)	March 31, 2022	December 31, 2021
Current:		
Senior notes	$ 100,600	$ 100,600
Long-term:		
Bank credit facilities	291,202	397,971
Senior notes	203,200	203,200
Total debt	$ 595,002	$ 701,771

Bank Credit Facilities

During the quarter, 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 $1.8 million of unamortized debt issuance costs remaining at March 31, 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 $1.4 million of debt issuance costs remaining unamortized and included in Other current assets at March 31, 2022.

For the three months ended March 31, 2022, total amortization of debt issuance costs amounted to $0.4 million (2021 – $0.1 million).

Senior Notes

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	Bullet payment on May 15, 2022	4.40%	$20,000	$20,000
May 15, 2012	May 15 and Nov 15	3 equal annual installments beginning May 15, 2022	4.40%	$355,000	$178,800
				Total carrying value at March 31, 2022	$ 303,800

Capital Management

Enerplus considers net debt to be a key measure of capital management, which is calculated as current and long-term debt associated with senior notes plus any outstanding bank credit facility balances, minus cash and cash equivalents.

The following table calculates net debt at March 31, 2022 and December 31, 2021:

($ thousands)	March 31, 2022	December 31, 2021
Current portion of long-term debt	$ 100,600	$ 100,600
Long-term debt	494,402	601,171
Total debt	$ 595,002	$ 701,771
Less: Cash and cash equivalents	(22,731)	(61,348)
Net debt	$ 572,271	$ 640,423

9) ASSET RETIREMENT OBLIGATION ("ARO")

($ thousands)	March 31, 2022	December 31, 2021
Balance, beginning of year	$ 132,814	$ 102,325
Change in estimates	18,346	26,586
Property acquisitions and development activity	1,010	1,304
Bruin acquisition (Note 6)	—	21,964
Dunn County acquisition (Note 6)	—	5,880
Divestments (Note 6)	(32)	(13,525)
Settlements	(8,795)	(12,951)
Government assistance	(400)	(4,594)
Accretion expense	1,648	5,825
Balance, end of period	$ 144,591	$ 132,814

Enerplus has estimated the present value of its ARO to be $144.6 million at March 31, 2022 based on a total undiscounted uninflated liability of $333.3 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 months ended March 31, 2022, Enerplus benefited from $0.4 million (2021 – $1.3 million), in government assistance, which has been recorded as other income in the Condensed Consolidated Statements of Income/(Loss).

For the three months ended March 31, 2022, Enerplus recognized $13.1 million as part of other expense in the Condensed Consolidated Statements of Income/(Loss) to fulfil abandonment and reclamation obligation requirements on previously disposed of assets.

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)	March 31, 2022	December 31, 2021
Assets		
Operating right-of-use assets	$ 24,492	$ 26,118
Liabilities		
Current operating lease liabilities	$ 10,852	$ 10,618
Non-current operating lease liabilities	16,310	18,265
Total lease liabilities	$ 27,162	$ 28,883
Weighted average remaining lease term (years)		
Operating leases	3.0	3.3
Weighted average discount rate		
Operating leases	3.4%	3.4%

The Company's lease contract expenditures/(income) for the three months ended March 31, 2022 and 2021 are as follows:

	Three months ended March 31,	
($ thousands)	2022	2021
Operating lease cost	$ 2,900	$ 2,857
Variable lease cost	1,145	24
Short-term lease cost	1,651	555
Sublease income	(234)	(191)
Total	$ 5,462	$ 3,245

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 March 31, 2022 or December 31, 2021.

Maturities of lease liabilities, all of which are classified as operating leases at March 31, 2022 are as follows:

($ thousands)		Operating Leases
2022	$	8,778
2023		10,673
2024		6,105
2025		1,006
2026		965
After 2026		1,153
Total lease payments	$	28,680
Less imputed interest		(1,518)
Total discounted lease payments	$	27,162
Current portion of lease liabilities	$	10,852
Non-current portion of lease liabilities	$	16,310

Supplemental information related to leases is as follows:

	Three months ended March 31,			
($ thousands)		2022		2021
Cash amounts paid to settle lease liabilities:				
Operating cash flow used for operating leases	$	3,190	$	3,078
Right-of-use assets obtained/(terminated) in exchange for lease liabilities:				
Operating leases	$	952	$	2,163

11) CRUDE OIL AND NATURAL GAS SALES

Crude oil and natural gas revenue by country and by product for the three months ended March 31, 2022 and 2021 are as follows:

Three months ended March 31, 2022 ($ thousands)		Total revenue		Crude oil(1)		Natural gas(1)		Natural gas liquids(1)		Other(2)
United States	$	472,247	$	357,657	$	87,496	$	27,090	$	4
Canada		40,905		36,547		2,781		1,392		185
Total	$	513,152	$	394,204	$	90,277	$	28,482	$	189

Three months ended March 31, 2021 ($ thousands)		Total revenue		Crude oil(1)		Natural gas(1)		Natural gas liquids(1)		Other(2)
United States	$	200,883	$	140,290	$	48,088	$	12,497	$	8
Canada		27,507		23,146		3,079		1,044		238
Total	$	228,390	$	163,436	$	51,167	$	13,541	$	246

(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

	Three months ended March 31,			
($ thousands)		2022		2021
General and administrative expense(1)	$	11,103	$	10,261
Share-based compensation expense		6,478		2,580
General and administrative expense	$	17,581	$	12,841

(1) Includes a non-cash lease credit of $95 for the three months ended March 31, 2022 (2021 – credit of $90).

13) FOREIGN EXCHANGE

($ thousands)	Three months ended March 31, 2022	2021
Realized:		
Foreign exchange (gain)/loss	$ (294)	$ (537)
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	10	356
Unrealized:		
Foreign exchange (gain)/loss on U.S. dollar working capital in parent company	1,171	157
Foreign exchange (gain)/loss	$ 887	$ (24)

14) INCOME TAXES

($ thousands)	Three months ended March 31, 2022	2021
Current tax		
United States	$ 5,000	$ —
Canada	—	—
Current tax expense/(recovery)	5,000	—
Deferred tax		
United States	$ 56,468	$ 18,940
Canada	(46,686)	(10,283)
Deferred tax expense/(recovery)	9,782	8,657
Income tax expense/(recovery)	$ 14,782	$ 8,657

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 $374.2 million at March 31, 2022 (December 31, 2021 – $380.9 million).

15) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued:	Three months ended March 31, 2022		Year ended December 31, 2021	
(thousands)	Shares	Amount	Shares	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	(3,135)	(31,342)	(12,898)	(128,686)
Non-cash:				
Share-based compensation – treasury settled(1)	1,240	7,959	1,140	9,402
Balance, end of period	241,957	$ 3,070,678	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 months ended March 31, 2022 were $7.9 million (2021 – $5.6 million). Subsequent to the quarter, the Board of Directors approved a 30% increase to the dividend to $0.043 per share to be effective for the June 2022 payment.

On August 12, 2021 Enerplus received approval from the Toronto Stock Exchange ("TSX") to commence a Normal Course Issuer Bid ("NCIB") to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. During the three months ended March 31, 2022, 3,134,700 common shares were repurchased and cancelled under the NCIB at an average price of $11.87 per share, for total consideration of $37.2 million. Of the amount paid, $31.3 million was charged to share capital and $5.9 million was credited to accumulated deficit. The Company did not have an NCIB in place during the three months ended March 31, 2021.

Subsequent to March 31, 2022 and up to and including May 4, 2022, the Company repurchased 1,494,996 common shares under the current NCIB at an average price of $12.61 per share, for total consideration of $18.9 million.

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):

	Three months ended March 31,	
($ thousands)	2022	2021
Cash:		
Long-term incentive plans expense	$ 2,098	$ 2,159
Non-Cash:		
Long-term incentive plans expense	4,755	892
Equity swap gain	(375)	(471)
Share-based compensation expense	$ 6,478	$ 2,580

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 three months ended March 31, 2022:

	Cash-settled LTI plans	Equity-settled LTI plans		Total
(thousands of units)	Director Plans	PSU[1]	RSU	
Balance, beginning of year	589	3,983	3,065	7,637
Granted	82	756	773	1,611
Vested	(45)	(827)	(1,300)	(2,172)
Forfeited	—	(35)	(13)	(48)
Balance, end of period	626	3,877	2,525	7,028

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

Cash-settled LTI Plans

For the three months ended March 31, 2022, the Company recorded a cash share-based compensation expense of $2.1 million (March 31, 2021 – $2.2 million).

As of March 31, 2022, a liability of $8.0 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 March 31, 2022 ($ thousands, except for years)	PSU[1]	RSU	Total
Cumulative recognized share-based compensation expense	$ 7,843	$ 5,973	$ 13,816
Unrecognized share-based compensation expense	12,835	9,744	22,579
Fair value	$ 20,678	$ 15,717	$ 36,395
Weighted-average remaining contractual term (years)	2.2	1.8	

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the three months ended March 31, 2022, $11.6 million (2021 – $3.6 million) 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 March 31,	
(thousands, except per share amounts)	2022	2021
Net income/(loss)	$ 33,243	$ 10,349
Weighted average shares outstanding – Basic	242,787	244,066
Dilutive impact of share-based compensation	6,550	2,832
Weighted average shares outstanding – Diluted	249,337	246,898
Net income/(loss) per share		
Basic	$ 0.14	$ 0.04
Diluted	$ 0.13	$ 0.04

16) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At March 31, 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 March 31, 2022, the senior notes had a carrying value of $303.8 million and a fair value of $303.0 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 March 31, 2022, Enerplus has equity, 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 months ended March 31, 2022 and 2021:

Gain/(Loss) ($ thousands)	Three months ended March 31, 2022	Three months ended March 31, 2021	Income Statement Presentation
Equity Swaps	$ 375	$ 471	G&A expense
Commodity Contracts:			
Crude oil	(95,706)	(41,857)	Commodity derivative instruments
Natural gas	(38,001)	1,028	
Total Unrealized Gain/(Loss)	$ (133,332)	$ (40,358)	

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

($ thousands)	Three months ended March 31, 2022	Three months ended March 31, 2021
Unrealized change in fair value gain/(loss)	$ (133,707)	$ (40,829)
Net realized gain/(loss)	(73,103)	(15,434)
Commodity contracts gain/(loss)	$ (206,810)	$ (56,263)

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

	March 31, 2022		December 31, 2021		
	Liabilities		Assets	Liabilities	
($ thousands)	Current	Long-term	Current	Current	Long-term
Equity Swaps	$ 640	$ —	$ —	$ 969	$ —
Commodity Contracts:					
Crude oil	221,486	13,866	1,771	141,364	7,098
Natural gas	34,912	—	3,897	867	—
Total	$ 257,038	$ 13,866	$ 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 March 31, 2022, the fair value of Enerplus' commodity contracts totaled a net liability of $270.3 million (December 31, 2021 – $143.7 million). Of this total net liability, $38.3 million (December 31, 2021 – $40.2 million) related to Bruin contracts, with $16.3 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 May 4, 2022:

Crude Oil Instruments:

Instrument Type[(1)(2)]	bbls/day	US$/bbl
Apr 1, 2022 – Jun 30, 2022		
WTI Purchased Put	12,500	75.00
WTI Sold Put	12,500	58.00
WTI Sold Call	12,500	87.63
April 1, 2022 – Dec 31, 2022		
WTI Purchased Put	17,000	50.00
WTI Sold Put	17,000	40.00
WTI Sold Call	17,000	57.91
WTI Sold Swap[(3)]	3,828	42.35
WTI Purchased Swap	3,828	66.52
Jan 1, 2023 – Jun 30, 2023		
WTI Purchased Put	10,000	76.50
WTI Sold Put	10,000	60.00
WTI Sold Call	10,000	107.38
Jan 1, 2023 – Oct 31, 2023		
WTI Sold Swap[(3)]	250	42.10
WTI Purchased Swap	250	64.85
WTI Purchased Put[(3)]	2,000	5.00
WTI Sold Call[(3)]	2,000	75.00
Nov 1, 2023 – Dec 31, 2023		
WTI Purchased Put[(3)]	2,000	5.00
WTI Sold Call[(3)]	2,000	75.00

(1) The total average deferred premium spent on the Company's outstanding crude oil contracts is $1.50/bbl from April 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 March 31, 2022, the remaining liability was $16.3 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)]	MMcf/day	US$/Mcf
Apr 1, 2022 – Oct 31, 2022		
NYMEX Swap	40.00	3.40
NYMEX Purchased Put	60.00	3.77
NYMEX Sold Call	60.00	4.50

(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 will 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 March 31, 2022, $303.8 million of senior notes and $293.0 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 months ended March 31, 2022, Other Comprehensive Income/(Loss) included an unrealized gain of $5.4 million on Enerplus' U.S. denominated senior notes and revolving bank credit facilities (2021 – $5.7 million gain).

Interest Rate Risk:

The Company's senior notes bear interest at fixed rates while the bank credit facilities bear interest at floating rates. At March 31, 2022, approximately 51% of Enerplus' debt was based on fixed interest rates and 49% on floating interest rates (December 31, 2021 – 43% fixed and 57% floating), with weighted average interest rates of 4.2% and 1.9%, respectively. At March 31, 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. Enerplus has entered into various equity swaps maturing in 2022 that effectively fix the future settlement cost on a portion of its cash settled LTI plans.

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 March 31, 2021, approximately 87% 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 March 31, 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 March 31, 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 months ended March 31, 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 March 31,	
($ thousands)	2022	2021
Accounts receivable	$ (54,591)	$ (52,454)
Other assets	4,305	2,447
Accounts payable – operating	(6,822)	(16,560)
Non-cash operating activities	$ (57,108)	$ (66,567)

b) Changes in Non-Cash Financing Working Capital

	Three months ended March 31,	
($ thousands)	2022	2021
Dividends payable	$ —	$ 297
Non-cash financing activities	$ —	$ 297

c) Changes in Non-Cash Investing Working Capital

	Three months ended March 31,	
($ thousands)	2022	2021
Accounts payable – investing[(1)]	$ 24,306	$ 11,775
Non-cash investing activities[(1)]	$ 24,306	$ 11,775

(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.

d) Cash Income Taxes and Interest Payments

	Three months ended March 31,	
($ thousands)	2022	2021
Income taxes paid/(received)	$ 7	$ 4
Interest paid	$ 5,206	$ 2,538

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

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

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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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