FIRST QUARTER REPORT

enerPLUS

Three Months Ended March 31, 2021

SELECTED FINANCIAL RESULTS	Three months ended March 31, 2021	Three months ended March 31, 2020
Financial (CDN$, thousands, except ratios)		
Net Income/(Loss)	$ 14,697	$ 2,876
Adjusted Net Income/(Loss)[1]	56,251	21,089
Cash Flow from Operating Activities	37,239	122,739
Adjusted Funds Flow[1]	128,048	113,227
Dividends to Shareholders - Declared	7,365	6,670
Total Debt Net of Cash[1]	794,170	514,620
Capital Spending	65,531	163,625
Property and Land Acquisitions	628,568	2,256
Property Divestments	4,995	5,578
Net Debt to Adjusted Funds Flow Ratio[1][2]	2.1x	0.8x
Financial per Weighted Average Shares Outstanding		
Net Income /(Loss) - Basic	$ 0.06	$ 0.01
Net Income/(Loss) - Diluted	0.06	0.01
Weighted Average Number of Shares Outstanding (000's) - Basic	244,066	222,357
Weighted Average Number of Shares Outstanding (000's) - Diluted	246,898	223,300
Selected Financial Results per BOE[3][4]		
Crude Oil & Natural Gas Sales[5]	$ 43.55	$ 31.96
Royalties and Production Taxes	(10.66)	(8.16)
Commodity Derivative Instruments	(2.35)	3.69
Operating Expenses	(7.82)	(8.84)
Transportation Costs	(3.98)	(3.95)
Cash General and Administrative Expenses	(1.59)	(1.37)
Cash Share-Based Compensation	(0.33)	0.31
Interest, Foreign Exchange and Other Expenses	(1.30)	(0.97)
Adjusted Funds Flow[1]	$ 15.52	$ 12.67

SELECTED OPERATING RESULTS	Three months ended March 31, 2021	Three months ended March 31, 2020
Average Daily Production[4]		
Crude Oil (bbls/day)	42,465	49,044
Natural Gas Liquids (bbls/day)	6,581	5,346
Natural Gas (Mcf/day)	255,749	262,913
Total (BOE/day)	91,671	98,209
% Crude Oil and Natural Gas Liquids	54%	55%
Average Selling Price [4][5]		
Crude Oil (per bbl)	$ 67.34	$ 51.30
Natural Gas Liquids (per bbl)	36.17	12.72
Natural Gas (per Mcf)	3.48	2.08
Net Wells Drilled	1	34

(1) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in the following MD&A.
(2) Ratio does not include trailing adjusted funds flow from the Bruin Acquisition.
(3) Non-cash amounts have been excluded.
(4) Based on Company interest production volumes. See "Basis of Presentation" section in the following MD&A.
(5) Before transportation costs, royalties and the effects of commodity derivative instruments.

Average Benchmark Pricing	Three months ended March 31, 2021	2020
WTI crude oil (US$/bbl)	$ 57.84	$ 46.17
Brent (ICE) crude oil (US$/bbl)	61.10	50.96
NYMEX natural gas – last day (US$/Mcf)	2.69	1.95
USD/CDN average exchange rate	1.27	1.34

Share Trading Summary For the three months ended March 31, 2021	CDN[1] - ERF (CDN$)	U.S.[2] - ERF (US$)
High	$ 7.22	$ 5.82
Low	$ 3.94	$ 3.07
Close	$ 6.31	$ 5.01

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

2021 Dividends per Share	CDN$	US$[1]
First Quarter Total	$ 0.03	$ 0.02

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

NEWS RELEASE

HIGHLIGHTS

- Adjusted funds flow was $128.0 million in the first quarter, which exceeded capital spending of $65.5 million, generating free cash flow of $62.5 million
- Delivered first quarter production of 91,671 BOE per day, including liquids of 49,046 barrels per day
- Completed two accretive acquisitions in the Williston Basin year to date, increasing Enerplus' acreage position in North Dakota by over four times to 296,000 net acres and extending its high-return development inventory
- Expect to deliver a 20% total well cost reduction in North Dakota in 2021 compared to 2019 through continued technology application and innovation
- Maintaining a solid financial position: net debt to adjusted funds flow ratio expected to be 1.3x or less by year-end 2021 based on US$55 per barrel WTI (annualized for 2021 acquisitions); current undrawn capacity on bank credit facility of approximately US$750 million
- Increasing the dividend and transitioning to quarterly payments: new quarterly dividend of $0.033 per share, a 10% increase from the current monthly dividend of $0.01 per share on an annualized basis, will be payable on June 15, 2021 to shareholders of record on May 28, 2021. Given the April and May dividends have already been paid or declared, the change to quarterly payments beginning in June represents an incremental dividend payment of $5.6 million in the second quarter of 2021

"It has been a constructive start to the year for us, having announced and closed two strategic acquisitions in the Bakken," said Ian C. Dundas, President and CEO. "These acquisitions are expected to be highly accretive to our per share metrics, support continued operational efficiencies and extend our core Bakken development inventory. They are also helping to drive a step change in the free cash flow generation of our business. As a result, and consistent with our commitment to sustainably growing our return of capital to shareholders, we are increasing our dividend. As we continue integration efforts, we remain focused on delivering safe, consistent execution under a disciplined capital allocation framework."

FIRST QUARTER SUMMARY

Production in the first quarter of 2021 was 91,671 BOE per day, a decrease of 7% compared to the same period a year ago, and 6% higher than the prior quarter. Crude oil and natural gas liquids production in the first quarter of 2021 was 49,046 barrels per day, a decrease of 10% compared to the same period a year ago, and approximately flat to the prior quarter. The lower production compared to the same period in 2020 was due to the significant reduction in capital activity in 2020 in response to the low commodity price environment. Quarter-over-quarter production was higher due to increased Marcellus volumes and the contribution of approximately 6,300 BOE per day from the Company's acquisition of Bruin which closed on March 10, 2021.

Enerplus reported first quarter 2021 net income of $14.7 million, or $0.06 per share, compared to net income of $2.9 million, or $0.01 per share, in the same period in 2020. Adjusted net income for the first quarter of 2021 was $56.3 million, or $0.23 per share, compared to $21.1 million, or $0.09 per share, during the same period in 2020. Net income and adjusted net income were higher compared to the prior year period primarily due to higher benchmark commodity prices and stronger commodity price realizations during the first quarter of 2021.

Enerplus' first quarter 2021 realized Bakken oil price differential was US$3.12 per barrel below WTI, compared to US$5.26 per barrel below WTI in the first quarter of 2020. The improved year-over-year Bakken differential was supported by increased refinery demand in the first quarter of 2021, while regional production was and continues to be lower than pre-pandemic levels.

The Company's realized Marcellus natural gas price differential was US$0.15 per Mcf below NYMEX during the first quarter of 2021, compared to US$0.38 per Mcf below NYMEX in the first quarter of 2020. Marcellus pricing is generally stronger during the first quarter associated with an increase in seasonal demand due to the onset of colder weather. The Company continues to expect significant seasonality in pricing in the U.S. Northeast moving through the rest of the year.

In the first quarter of 2021, Enerplus' operating costs were $7.82 per BOE, transportation costs were $3.98 per BOE and cash general and administrative expenses were $1.59 per BOE.

Exploration and development capital spending totaled $65.5 million in the first quarter of 2021. The Company paid $7.4 million in dividends in the quarter.

Enerplus ended the first quarter of 2021 with total debt of $983.2 million and cash of $189.0 million. Subsequent to the first quarter, the Company increased and extended its senior, unsecured bank credit facility to US$900 million (from US$600 million) with a maturity date extended to October 31, 2025. The Company also transitioned this facility to a sustainability-linked credit facility ("SLL credit facility"), incorporating sustainability-linked performance targets (see the Company's news release dated April 29, 2021).

ASSET HIGHLIGHTS

Williston Basin production averaged 47,327 BOE per day (73% tight oil), inclusive of production acquired through the Bruin acquisition which closed on March 10, 2021. This is a decrease of 4% compared to the same period a year ago, and 3% higher than the prior quarter. The Company brought three gross operated wells (100% working interest) on production late in the first quarter. The Company reinitiated its drilling program in North Dakota early in the second quarter and plans to continue running one drilling rig for the rest of the year. Enerplus is continuing to drive durable well cost efficiencies, with the average cost for a two-mile lateral expected to decline to US$6.1 million in 2021, a 20% reduction compared to 2019.

Marcellus production averaged 204 MMcf per day during the first quarter of 2021, a decrease of 6% compared to the same period in 2020, and 16% higher than the prior quarter. The Company participated in drilling 14 gross non-operated wells (1% average working interest) and brought 16 gross non-operated wells (3% average working interest) on production during the quarter.

Canadian waterflood production averaged 7,383 (97% oil) during the first quarter of 2021, a decrease of 10% compared to the same period in 2020, and 4% lower than the prior quarter.

In the DJ Basin, Enerplus brought three gross operated wells (86% average working interest) on production during the first quarter.

ACQUISITIONS UPDATE

Enerplus announced two strategic acquisitions in the Williston Basin year to date, which are expected to deliver meaningful accretion to per share metrics, enhance the Company's free cash flow outlook, extend its high-return drilling inventory and support further operational efficiencies.

The Company's acquisition of Bruin for total cash consideration of US$465 million (prior to closing adjustments), closed on March 10, 2021. The Company's acquisition of assets from Hess Corporation for total cash consideration of US$312 million (prior to closing adjustments), closed on April 30, 2021. Enerplus continues to maintain excellent liquidity and had approximately US$750 million undrawn capacity on its US$900 million SLL credit facility as at May 1, 2021.

DIVIDEND INCREASE; QUARTERLY PAYMENTS

Enerplus' Board of Directors approved a 10% increase to the Company's dividend to $0.033 per share paid quarterly, from $0.01 per share paid monthly previously. The first increased quarterly dividend is payable on June 15, 2021 to all shareholders of record at the close of business on May 28, 2021. The ex-dividend date for this payment is May 27, 2021.

2021 GUIDANCE UPDATE

Production and capital spending guidance for 2021 remains unchanged and is summarized in the table below. Capital spending is expected to be split relatively evenly between the first and second half of the year. Approximately 80% of the Company's 2021 capital budget is allocated to its North Dakota operations where it expects to drill 21 gross (21 net) operated wells and bring 42 gross (32 net) operated wells on production during the year. In addition to this operated activity, the budget includes an allocation for non-operated activity in North Dakota.

Operating expenses in 2021 are expected to average $8.25 per BOE. Unit operating expenses are expected to increase following the first quarter due to the Company's increased liquids production weighting from its recent acquisitions. Enerplus' first quarter production was 54% liquids which is expected to increase above 60% liquids for the rest of 2021.

Transportation and cash general and administrative ("G&A") expenses in 2021 are expected to average $3.85 per BOE and $1.25 per BOE, respectively.

2021 Guidance	
Capital spending	$360 to $400 million
Average annual production	111,000 to 115,000 BOE/day
Average annual crude oil and natural gas liquids production	68,500 to 71,500 bbls/day
Average royalty and production tax rate	26%
Operating expense	$8.25/BOE
Transportation expense	$3.85/BOE
Cash G&A expense	$1.25/BOE

2021 Full-Year Differential/Basis Outlook[1]	
U.S. Bakken crude oil differential (compared to WTI crude oil)[2]	US$(3.25)/bbl
Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.55)/Mcf

(1) Excluding transportation costs.
(2) Assuming the Dakota Access Pipeline ("DAPL") continues to operate.

PRICE RISK MANAGEMENT

Enerplus' latest commodity hedging positions are provided in the table below.

Enerplus' Financial Commodity Hedging Contracts (As at May 5, 2021)

	WTI Crude Oil (US$bbl)[(1)(2)]					NYMEX Natural Gas (US$/Mcf)
	Apr 1, 2021 – Jun 30, 2021	Jul 1, 2021 – Dec 31, 2021	Jan 1, 2022 – Dec 31, 2022	Jan 1, 2023 – Oct 31, 2023	Nov 1, 2023 – Dec 31, 2023	Apr 1, 2021 – Oct 31, 2021
Swaps						
Volume (bbls/day)	–	–	–	–	–	60,000
Sold Swaps	–	–	–	–	–	$ 2.90
Three Way Collars						
Volume (bbls/day)	20,000	23,000	17,000	–	–	40,000
Sold Puts	$ 32.00	$ 36.39	$ 40.00	–	–	$ 2.15
Purchased Puts	$ 40.90	$ 46.39	$ 50.00	–	–	$ 2.75
Sold Calls	$ 50.72	$ 56.70	$ 57.91	–	–	$ 3.25
Hedges acquired from Bruin[(3)]						
Swaps						
Volume (bbls/day)	9,750	8,465	3,828	250	–	–
Sold Swaps	$ 42.16	$ 42.52	$ 42.35	$ 42.10	–	–
Collars						
Volume (bbls/day)	–	–	–	2,000	2,000	–
Purchased Puts	–	–	–	$ 5.00	$ 5.00	–
Sold Calls	–	–	–	$ 75.00	$ 75.00	–

(1) The total average deferred premium spent on outstanding hedges is US$0.67/bbl from April 1, 2021 - December 31, 2021 and US$1.22/bbl from January 1, 2022 - December 31, 2022.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Upon close of the Bruin acquisition, Bruin's outstanding hedges were recorded at a fair value on the balance sheet. Realized and unrealized gains and losses on the acquired hedges are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the date of the close of the Bruin acquisition. For the three months ended March 31, 2021, Enerplus recognized an unrealized gain of $17.4 million in the Consolidated Statement of Income/(Loss). The Bruin hedges were in a liability position of $70.9 million at March 31, 2021.

Q1 2021 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 7, 2021 to discuss these results. Details of the conference call are as follows:

Date: Friday, May 7, 2021
Time: 9:00 AM MT (11:00 AM ET)
Dial-In: 587-880-2171 (Alberta)
1-888-390-0546 (Toll Free)
Conference ID: 35089571
Audiocast: https://produceredition.webcasts.com/starthere.jsp?ei=1450753&tp_key=6e8d1a2524

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: 089571 #

Summary of Average Daily Production[1]

	Three months ended March 31, 2021				
	Williston Basin	Marcellus	Canadian Waterfloods	Other[2]	Total
Tight oil (bbl/d)	34,489	—	—	787	35,275
Light & medium oil (bbl/d)	—	—	3,040	32	3,072
Heavy oil (bbl/d)	—	—	4,108	9	4,118
Total crude oil (bbl/d)	**34,489**	—	**7,149**	**828**	**42,465**
Natural gas liquids (bbl/d)	5,993	—	26	562	6,581
Shale gas (Mcf/d)	41,069	203,985	—	1,136	246,191
Conventional natural gas (Mcf/d)	—	—	1,255	8,303	9,558
Total natural gas (Mcf/d)	**41,069**	**203,985**	**1,255**	**9,439**	**255,748**
Total Production (BOE/d)	**47,327**	**33,998**	**7,383**	**2,964**	**91,671**

(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, 2021			
	Operated		Non Operated	
	Gross	Net	Gross	Net
Williston Basin	—	—	—	—
Marcellus	—	—	14	0.2
Canadian Waterfloods	—	—	—	—
Other[2]	—	—	2	0.3
Total	**—**	**—**	**16**	**0.5**

(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, 2021			
	Operated		Non Operated	
	Gross	Net	Gross	Net
Williston Basin	3	3.0	—	—
Marcellus	—	—	16	0.4
Canadian Waterfloods	—	—	—	—
Other[2]	3	2.6	2	0.3
Total	**6**	**5.6**	**18**	**0.7**

(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 Canadian 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 Measures".

Barrels of Oil Equivalent
This news release also 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.

Presentation of Production Information
Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under Canadian disclosure requirements and industry practice, oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. All production volumes and oil and gas sales presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest.

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 natural gas liquids on a combined basis.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("forward-looking information"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "believes" and "plans" 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: expected benefits of the Hess asset and Bruin acquisition; expected impact of the Hess asset and Bruin acquisitions on Enerplus' operations and financial results; anticipated impact of the Hess asset and Bruin acquisitions on Enerplus' future costs and expenses; expectations regarding the duration and overall impact of COVID-19; expected capital spending levels in 2021 and in the future, timing thereof; and the impact thereof on our production levels and land holdings; expected production volumes and 2021 and future production guidance; expected operating strategy in 2021; 2021 average production volumes, timing thereof 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 adjusted funds flow in 2021 and the future; the results from our drilling program and the timing of related production and ultimate well recoveries; oil and natural gas prices and differentials, our commodity risk management program in 2021 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating, transportation, cash G&A and financing costs; expected reduction in well costs; future royalty rates on our production and future production taxes; net debt to adjusted funds-flow ratio, financial capacity and liquidity and capital resources to fund capital spending, dividends and working capital requirements; expectations regarding payment of increased dividends.

The forward-looking information contained in this news release reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated, including considering the Hess asset and Bruin acquisition; that our development plans will achieve the expected results; that a lack of adequate infrastructure and/or low commodity price environment will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current and estimated commodity prices, differentials and cost assumptions; the continued ability to operate DAPL and lack of court order restricting its operation, that our development plans will achieve the expected results; the general continuance of current or, where applicable, assumed industry conditions, including 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 continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to comply with our debt covenants; the availability of third party services; the extent of our liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; the availability of technology and processes to achieve environmental targets. In addition, Enerplus' 2021 outlook contained in this news release is based on the following: a WTI price of between US$50 and US$55.00/bbl, a NYMEX price of US$3.00/Mcf, a Bakken crude oil price differential of US$3.25/bbl below WTI and a USD/CDN exchange rate of 1.27. We believe 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.

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; continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; failure to realize the anticipated benefits of the Hess asset and Bruin acquisitions; unanticipated operating results, results from our capital spending activities or production declines; the legal proceedings in connection with 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; 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 facility and 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 and contingencies described under "Risk Factors and Risk Management" in Enerplus' 2020 MD&A and in our other public filings).

The forward-looking information contained in this press release speaks only as of the date of this press release, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

NON-GAAP MEASURES

In this news release, Enerplus uses the terms "adjusted funds flow", "adjusted net income", "free cash flow" and "net debt to adjusted funds flow ratio" measures to analyze operating performance, leverage and liquidity. "Adjusted funds flow" is calculated as net cash generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Adjusted net income" is calculated as net income adjusted for unrealized derivative instrument gain/loss, asset impairment, gain on divestment of assets, unrealized foreign exchange gain/loss, and the tax effect of these items. "Free cash flow" is calculated as adjusted funds flow minus capital spending. "Net debt to adjusted funds flow" is calculated as total debt net of cash, including restricted cash, divided by adjusted funds flow.

Enerplus believes that, in addition to cash flow from operating activities, net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "adjusted net income", "free cash flow" and "net debt to adjusted funds flow" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S. GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in Enerplus' 2020 MD&A.

Electronic copies of Enerplus Corporation's First Quarter 2021 MD&A and Financial Statements, along with other public information including investor presentations, are available on its website at www.enerplus.com. Shareholders may, upon request, receive a printed copy of the Company's audited financial statements at any time. 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 6, 2021 and is to be read in conjunction with:

- the unaudited interim condensed consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three months ended March 31, 2021 and 2020 (the "Interim Financial Statements");

- the audited consolidated financial statements of Enerplus as at December 31, 2020 and 2019 and for the years ended December 31, 2020, 2019 and 2018; and

- our MD&A for the year ended December 31, 2020 (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, 2020 (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 amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included in the Interim Financial Statements. 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. Unless otherwise stated, all production volumes and realized product prices information is presented on a "Company interest" basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and 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.

In accordance with U.S. GAAP, crude oil and natural gas sales are presented net of royalties in our Interim Financial Statements. Under International Financial Reporting Standards, industry standard is to present crude oil and natural gas sales before deduction of royalties, and as such, this MD&A presents production, crude oil and natural gas sales, and BOE measures on this basis to remain comparable with our Canadian peers.

Unless otherwise expressly stated, information presented in this MD&A does not give effect to the acquisition (the "Hess Acquisition") by Enerplus Resources (USA) Corporation, an indirect wholly-owned subsidiary of the Company, of certain assets in the Williston Basin from Hess Bakken Investments II, LLC ("Hess"), as announced on April 8, 2021. The Hess Acquisition closed on April 30, 2021. See the material change report dated April 16, 2021 in connection with the Hess Acquisition available under Enerplus' SEDAR profile at www.sedar.com and on Enerplus' EDGAR profile under Form 6-K at www.sec.gov.

For more details on our acquisition (the "Bruin Acquisition") of Bruin E&P HoldCo, LLC ("Bruin"), see Note 4 to the Interim Financial Statements as well as the material change report dated January 29, 2021 and the business acquisition report dated April 13, 2021, each available under Enerplus' SEDAR profile at www.sedar.com and Enerplus' EDGAR profile under Form 6-K at www.sec.gov.

OVERVIEW

During the first quarter of 2021, global economies began to recover from the impacts brought on by the coronavirus ("COVID-19") pandemic. Demand for crude oil improved and prices returned to pre-COVID-19 levels, bringing some stability to our industry.

On January 25, 2021, we entered into a purchase and sale agreement to acquire all of the outstanding equity interests of Bruin a private company that holds oil and gas interests in certain properties located in the Williston Basin in North Dakota. The Bruin Acquisition was completed on March 10, 2021 and the cash purchase price of approximately US$465 million, prior to the preliminary purchase price adjustments of US$47 million, was funded by a new three-year US$400 million term loan and through a portion of the proceeds of a bought deal public offering of common shares, which was completed on February 3, 2021. Bruin's assets were producing approximately 24,000 BOE/day (72% tight oil, 14% natural gas liquids, and 14% natural gas) upon completion of the transaction.

On April 8, 2021, we announced that we had entered into a purchase and sale agreement to acquire certain assets in the Williston Basin from Hess for total cash consideration of US$312 million, subject to customary purchase price adjustments. The Hess Acquisition closed on April 30, 2021 and was funded using our existing cash balance and drawing on our bank credit facility. The Hess assets have production of approximately 6,000 BOE/day (76% tight oil, 10% natural gas liquids, and 14% natural gas). We expect the Bruin Acquisition and Hess Acquisition to contribute meaningful free cash flow and provide additional core inventory while increasing the scope and scale of our business.

Production during the first quarter of 2021 averaged 91,671 BOE/day, a 6% increase compared to production of 86,244 BOE/day in the fourth quarter of 2020. The increased production was driven by strong well performance in North Dakota and the Marcellus. Bruin's assets, which were acquired on March 10, 2021, contributed 6,300 BOE/day of production in the first quarter of 2021. This increase was offset by natural production declines in our portfolio as capital spending on our 2021 program began in February and we had limited capital spending throughout 2020. Our 2021 production volumes are expected to average 111,000 to 115,000 BOE/day including 68,500 to 71,500 bbls/day of liquids production with an eight month contribution from the Hess Acquisition in 2021.

Capital spending during the first quarter of 2021 totaled $65.5 million, compared to $52.4 million during the fourth quarter of 2020. The majority of the spending was focused on our U.S. crude oil properties, as we initiated our completion program in North Dakota resulting in a total of 5.6 net operated wells and 0.7 non-operated wells coming on-stream late in the quarter. We expect capital spending for 2021 of between $360 to $400 million.

Our realized Bakken crude oil price differential narrowed to average US$3.12/bbl below WTI during the first quarter of 2021 compared to US$4.82/bbl below WTI during the fourth quarter of 2020. Bakken differentials in North Dakota were supported by increased refinery demand, while production remained stable. We expect our annual Bakken crude oil price differential to average US$3.25/bbl below WTI for 2021, assuming the continued operation of the Dakota Access Pipeline ("DAPL").

Our realized Marcellus natural gas price differential averaged US$0.15/Mcf below NYMEX in the first quarter of 2021, compared to US$1.07/Mcf below NYMEX during the fourth quarter of 2020, as demand increased with the colder winter weather in the first quarter. We expect our annual Marcellus natural gas price differential to average US$0.55/Mcf below NYMEX.

Operating costs for the first quarter of 2021 were in line with the fourth quarter of 2020 and decreased on a per BOE basis to $64.5 million or $7.82/BOE, compared to $65.1 million or $8.20/BOE respectively, due to higher natural gas production in the Marcellus. We expect operating expenses to average $8.25/BOE, during 2021.

We reported net income of $14.7 million in the first quarter of 2021 compared to a net loss of $204.2 million in the fourth quarter of 2020. The net income recognized in the first quarter of 2021 was primarily due to higher production and commodity prices along with a significantly lower non-cash property, plant and equipment ("PP&E") impairment of $4.3 million compared to the fourth quarter of 2020, where we recorded a $311.2 million non-cash PP&E impairment.

Cash flow from operations decreased to $37.2 million in the first quarter of 2021 compared to $96.1 million in the fourth quarter of 2020 primarily due to changes in working capital. Higher accrued revenue receivables at March 31, 2021 was a result of higher commodity prices and higher production during the first quarter of 2021, compared to December 31, 2020. First quarter adjusted funds flow increased to $128.0 million from $91.9 million over the same period. The increase was primarily due to higher production and an improvement in commodity prices during the quarter.

At March 31, 2021, our total debt net of cash was $794.2 million, compromised of senior notes and term loan totaling $983.2 million, less cash on hand of $189.0 million. Our net debt to adjusted funds flow ratio was 2.1x, which does not include the trailing adjusted funds flow associated with the Bruin Acquisition. At March 31, 2021 and as of the date of this MD&A, we are in compliance with all debt covenants.

Subsequent to the quarter end, we increased and extended our senior unsecured bank credit facility to US$900 million from US$600 million with a maturity of October 31, 2025. In addition, we transitioned the facility to a sustainability linked credit facility with three sustainability-linked performance targets, which reduce or increase our borrowing costs by up to 5 bps as the targets are exceeded or missed.

On May 6, 2021, the Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly, from $0.01 per share paid monthly previously. The increased quarterly dividend is payable on June 15, 2021 to all shareholders of record at the close of business on May 28, 2021. Given the April and May dividends have already been paid or declared, the change to quarterly payments beginning in June represents an incremental dividend payment of $5.6 million in the second quarter of 2021. This change is consistent with our commitment to sustainably grow our return of capital to shareholders

RESULTS OF OPERATIONS

Production

Daily production for the first quarter of 2021 averaged 91,671 BOE/day, an increase of 6% compared to average production of 86,244 BOE/day in the fourth quarter of 2020. Bruin's assets, which were acquired on March 10, 2021, contributed 6,300 BOE/day of production in the first quarter of 2021. Despite the contribution from Bruin, crude oil and natural gas liquids production was consistent with the fourth quarter of 2020 due to natural production declines in our portfolio as capital spending on our 2021 program began in February and we had limited capital spending throughout 2020. Natural gas production increased 8% to 255,749 Mcf/day in the first quarter of 2021 from 237,857 Mcf/day in the fourth quarter of 2020 due to increased on-stream activity in the Marcellus.

For the three months ended March 31, 2021, total production decreased by 7% when compared to the same period in 2020. The decrease in production was primarily due to the suspension of all operated drilling and completion activity in North Dakota during the second quarter of 2020 in response to the significant decline in crude oil prices. Our Marcellus natural gas production decreased by 6% due to limited capital activity in 2020. These impacts were partially offset by an increase in natural gas liquids production over the same period in part due to an increase in natural gas liquids recoveries.

Our crude oil and natural gas liquids weighting decreased to 54% in the first quarter of 2021 from 55% in the same period of 2020.

Average daily production volumes for the three months ended March 31, 2021 and 2020 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2021**	**2020**	**% Change**
Tight oil (bbls/day)	35,275	41,208	(14)%
Heavy oil (bbls/day)	4,118	4,356	(5)%
Light and medium oil (bbls/day)	3,072	3,480	(12)%
Total crude oil (bbls/day)	42,465	49,044	(13)%
Natural gas liquids (bbls/day)	6,581	5,346	23%
Shale gas (Mcf/day)	246,191	248,263	(1)%
Conventional natural gas (Mcf/day)	9,558	14,650	(35)%
Total natural gas (Mcf/day)	255,749	262,913	(3)%
Total daily sales (BOE/day)	91,671	98,209	(7)%

We expect annual average production for 2021 of 111,000 – 115,000 BOE/day, including 68,500 – 71,500 bbls/day in crude oil and natural gas liquids production, with a ten month contribution from the Bruin Acquisition and an eight month contribution from the Hess Acquisition in 2021.

Pricing

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

Pricing (average for the period)	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020
Benchmarks					
WTI crude oil (US$/bbl)	$ 57.84	$ 42.66	$ 40.93	$ 27.85	$ 46.17
Brent (ICE) crude oil (US$/bbl)	61.10	45.24	43.37	33.27	50.96
NYMEX natural gas – last day (US$/Mcf)	2.69	2.66	1.98	1.72	1.95
USD/CDN average exchange rate	1.27	1.30	1.33	1.39	1.34
USD/CDN period end exchange rate	1.26	1.27	1.33	1.36	1.41
Enerplus selling price(1)					
Crude oil ($/bbl)	$ 67.34	$ 47.95	$ 46.43	$ 30.55	$ 51.30
Natural gas liquids ($/bbl)	36.17	17.19	10.60	(0.96)	12.72
Natural gas ($/Mcf)	3.48	2.04	1.72	1.63	2.08
Average differentials					
Bakken DAPL – WTI (US$/bbl)	$ (2.63)	$ (3.45)	$ (3.40)	$ (5.24)	$ (5.34)
Brent (ICE) – WTI (US$/bbl)	3.26	2.58	2.44	5.42	4.79
MSW Edmonton – WTI (US$/bbl)	(5.24)	(3.91)	(3.51)	(6.14)	(7.58)
WCS Hardisty – WTI (US$/bbl)	(12.47)	(9.30)	(9.08)	(11.47)	(20.53)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.19)	(1.18)	(0.80)	(0.45)	(0.39)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	0.61	(0.85)	(0.56)	(0.37)	0.41
Enerplus realized differentials(1)(2)					
Bakken crude oil – WTI (US$/bbl)	$ (3.12)	$ (4.82)	$ (5.37)	$ (4.36)	$ (5.26)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.15)	(1.07)	(0.72)	(0.49)	(0.38)
Canada crude oil – WTI (US$/bbl)	(12.89)	(10.18)	(9.74)	(14.49)	(17.77)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

During the first quarter of 2021, our realized crude oil sales price averaged $67.34/bbl, an increase of 40% compared to the fourth quarter of 2020 and consistent with the increase in the benchmark WTI price over the same period. In the U.S., crude oil prices and price differentials strengthened as refinery demand increased due to improving market demand and the gradual easing of COVID-19 restrictions. Oil supply continues to be managed through ongoing extensions of the agreement made by the Organization of the Petroleum Exporting Countries Plus ("OPEC+") nations to curtail production from the market through mid-2022.

Our realized Bakken crude oil price differential averaged US$3.12/bbl below WTI during the first quarter of 2021 compared to US$4.82/bbl below WTI during the fourth quarter of 2020. Bakken differentials in North Dakota were supported by increased refinery demand specifically in the U.S. Midwest due to a record cold weather event in February, which significantly disrupted U.S. Gulf Coast refining activity. Additionally, regional production remains lower than pre-pandemic levels.

Our Bakken crude oil sales portfolio consists of a combination of in-basin monthly spot and index sales, term physical sales with fixed differential pricing versus WTI, sales at Cushing, and sales at the U.S. Gulf Coast delivered via firm capacity on DAPL. DAPL continues to operate despite ongoing legal challenges and further environmental review. Assuming the ongoing operation of DAPL, we expect our annual Bakken realized crude oil sales price differential to average approximately US$3.25/bbl below WTI in 2021.

Our realized Canadian crude oil price differential widened by US$2.71/bbl compared to the fourth quarter of 2020, which was in line with changes to the underlying benchmark prices.

Our realized sales price for natural gas liquids averaged $36.17/bbl during the first quarter of 2021, compared to $17.19/bbl in the fourth quarter of 2020. Natural gas liquids prices benefited substantially from the cold weather event in February which was centered over key natural gas liquids pricing hubs in both the Midwest and Texas.

NATURAL GAS

Our realized natural gas sales price averaged $3.48/Mcf during the first quarter of 2021, an increase of 70% compared to the fourth quarter of 2020. NYMEX benchmark prices increased by 1% over the same period as winter weather remained fairly neutral until late February when severe cold weather caused prices to increase significantly across many areas of the U.S.

Regional pricing in the Marcellus was much stronger during the first quarter of 2021, compared to the previous quarter, due to an increase in seasonal demand with the onset of colder winter weather. As a result, our realized Marcellus sales price differential narrowed to average US$0.15/Mcf below NYMEX during the quarter compared to US$1.07/Mcf below NYMEX in the fourth quarter of 2020. This narrowing was in line with the changes in the underlying benchmark basis pricing and significant seasonality in pricing we expect in the U.S. Northeast during the winter. We expect our Marcellus differential to average US$0.55/Mcf below NYMEX for the full year.

FOREIGN EXCHANGE

Our crude oil and natural gas sales are impacted by foreign exchange fluctuations as the majority of our sales are based on U.S. dollar denominated benchmark indices. A stronger Canadian dollar decreases the amount of our realized sales as well as the amount of our U.S. denominated costs, such as capital, the interest on our U.S. denominated debt, and the value of our outstanding U.S. senior notes and term loan.

The Canadian dollar continued to strengthen during the first quarter of 2021 in response to higher commodity prices as global economies stabilized and crude oil demand continued to recover from the onset of the COVID-19 pandemic in the first quarter of 2020. The Canadian dollar ended the first quarter at 1.26 USD/CAD, compared to 1.27 USD/CAD at December 31, 2020. The average exchange rate of 1.27 USD/CAD during the first quarter of 2021 was considerably stronger than the same period in 2020 when it averaged 1.34 USD/CAD.

Price Risk Management

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

We continue to expect our hedging contracts to protect a portion of our cash flow from operating activities and adjusted funds flow. As of May 5, 2021, we have hedged 30,900 bbls/day of crude oil for the remainder of 2021 and 20,800 bbls/day during 2022. We have also hedged 100,000 Mcf/day of natural gas for the period of April 1, 2021 to October 31, 2021. Our crude oil hedges consist of swaps and three way collars. The three way collars provide us with exposure to significant 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.

The following is a summary of our financial contracts in place at May 5, 2021:

	WTI Crude Oil (1)(2) (US$/bbl)					NYMEX Natural Gas (US$/Mcf)
	Apr 1, 2021 – Jun 30, 2021	**Jul 1, 2021 – Dec 31, 2021**	**Jan 1, 2022 – Dec 31, 2022**	**Jan 1, 2023 – Oct 31, 2023**	**Nov 1, 2023 – Dec 31, 2023**	**Apr 1, 2021 – Oct 31, 2021**
Swaps						
Volume (bbls/day)	–	–	–	–	–	60,000
Sold Swaps	–	–	–	–	–	$ 2.90
Three Way Collars						
Volume (bbls/day)	20,000	23,000	17,000	–	–	40,000
Sold Puts	$ 32.00	$ 36.39	$ 40.00	–	–	$ 2.15
Purchased Puts	$ 40.90	$ 46.39	$ 50.00	–	–	$ 2.75
Sold Calls	$ 50.72	$ 56.70	$ 57.91	–	–	$ 3.25
Hedges acquired from Bruin(3)						
Swaps						
Volume (bbls/day)	9,750	8,465	3,828	250	–	–
Sold Swaps	$ 42.16	$ 42.52	$ 42.35	$ 42.10	–	–
Collars						
Volume (bbls/day)	–	–	–	2,000	2,000	–
Purchased Puts	–	–	–	$ 5.00	$ 5.00	–
Sold Calls	–	–	–	$ 75.00	$ 75.00	–

(1) The total average deferred premium spent on our outstanding hedges is US$0.67/bbl from April 1, 2021 - December 31, 2021 and US$1.22/bbl from January 1, 2022 - December 31, 2022.
(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 hedges were recorded at a fair of $96.5 million value on the Condensed Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired hedges are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the date of closing of the Bruin Acquisition. See Note 17 to the Interim Financial Statements for further details.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	Three months ended March 31, 2021	2020
Cash gains/(losses):		
Crude oil	$ (20.1)	$ 33.0
Natural gas	0.7	—
Total cash gains/(losses)	$ (19.4)	$ 33.0
Non-cash gains/(losses):		
Crude oil	$ (51.7)	$ 98.3
Natural gas	1.3	—
Total non-cash gains/(losses)	$ (50.4)	$ 98.3
Total gains/(losses)	$ (69.8)	$ 131.3

(Per BOE)	Three months ended March 31, 2021	2020
Total cash gains/(losses)	$ (2.35)	$ 3.69
Total non-cash gains/(losses)	(6.11)	11.01
Total gains/(losses)	$ (8.46)	$ 14.70

We realized cash losses of $20.1 million on our crude oil contracts during the first quarter of 2021, compared to realized cash gains of $33.0 million for the same period in 2020. We recorded realized cash gains of $0.7 million on our natural gas contracts in the first quarter of 2021 and there were no natural gas derivative contracts outstanding during the first quarter of 2020.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At March 31, 2021, the fair value of our crude oil and natural gas contracts was in a net liability position of $150.9 million. For the three months ended March 31, 2021, the change in the fair value of our crude oil contracts resulted in an unrealized loss of $51.7 million compared to a gain of $98.3 million during the same period in 2020. We recorded an unrealized gain of $1.3 million during the first quarter of 2021 on our natural gas contracts.

On March 10, 2021, the outstanding crude oil hedges acquired with the Bruin Acquisition were recorded at fair value, resulting in a liability of $96.5 million on the Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired hedges are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the closing date of the Bruin Acquisition. For the three months ended March 31, 2021 we recorded a realized gain of $0.5 million on the first settlement of the Bruin hedges. We recognized an unrealized gain of $17.4 million in the Consolidated Statement of Income/(Loss) for the change in the fair value of the Bruin hedges during the first quarter of 2021. At March 31, 2021, the fair value of the Bruin hedges was a liability of $70.9 million. See Note 17 to the Interim Financial Statements for further detail.

Revenues

	Three months ended March 31,	
($ millions)	2021	2020
Crude oil and natural gas sales	$ 359.3	$ 285.6
Royalties	(70.5)	(57.5)
Crude oil and natural gas sales, net of royalties	$ 288.8	$ 228.1

Crude oil and natural gas sales, net of royalties, for the three months ended March 31, 2021 were $288.8 million, an increase of 27% from the same period in 2020. The increase in revenue was primarily due to higher realized prices, partially offset by lower production compared to the same period in 2020. See Note 12 to the Interim Financial Statements for further detail.

Royalties and Production Taxes

	Three months ended March 31,	
($ millions, except per BOE amounts)	2021	2020
Royalties	$ 70.5	$ 57.5
Per BOE	$ 8.54	$ 6.43
Production taxes	$ 17.5	$ 15.4
Per BOE	$ 2.12	$ 1.73
Royalties and production taxes	$ 88.0	$ 72.9
Per BOE	$ 10.66	$ 8.16
Royalties and production taxes (% of crude oil and natural gas sales)	24.5%	25.5%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees and freehold mineral taxes. A large percentage of our production is from U.S. properties where royalty rates are generally higher than in Canada. Royalties and production taxes for the three months ended March 31, 2021 were $88.0 million, an increase of 21% from the same period in 2020. Total royalties increased due to higher realized prices and revenues. The decrease in royalty rate is primarily due to improved natural gas and natural gas liquids prices as these products have a lower royalty rate.

We expect annual royalties and production taxes in 2021 to average 26% of crude oil and natural gas sales before transportation.

Operating Expenses

	Three months ended March 31,	
($ millions, except per BOE amounts)	2021	2020
Operating expenses	$ 64.5	$ 79.0
Per BOE	$ 7.82	$ 8.84

For the three months ended March 31, 2021, operating expenses were $64.5 million, or $7.82/BOE, a decrease of $14.5 million, or $1.02/BOE, from the same period in 2020. This decrease was primarily due to lower U.S. crude oil production which has higher per BOE operating costs and a stronger Canadian dollar when compared to the same period in 2020.

We expect operating expenses of $8.25/BOE in 2021, an increase from the first quarter of 2021 due to the expected increase in our crude oil and natural gas liquids production weighting with the Bruin and Hess acquisitions.

Transportation Costs

	Three months ended March 31,	
($ millions, except per BOE amounts)	2021	2020
Transportation costs	$ 32.8	$ 35.3
Per BOE	$ 3.98	$ 3.95

For the three months ended March 31, 2021, transportation costs were $32.8 million, or $3.98/BOE, compared to $35.3 million, or $3.95/BOE, for the same period in 2020. This represents a decrease of $2.5 million in total transportation costs and an increase of $0.03/BOE. The reduction in transportation costs was primarily due to the impact of a stronger Canadian dollar compared to the same period in 2020.

We expect transportation costs of $3.85/BOE in 2021.

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, 2021		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	55,652 BOE/day	216,115 Mcfe/day	91,671 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 59.02	$ 3.27	$ 43.55
Royalties and production taxes	(15.09)	(0.63)	(10.66)
Operating expenses	(12.17)	(0.18)	(7.82)
Transportation costs	(3.06)	(0.90)	(3.98)
Netback before hedging	$ 28.70	$ 1.56	$ 21.09
Cash hedging gains/(losses)	(4.02)	0.04	(2.35)
Netback after hedging	$ 24.68	$ 1.60	$ 18.74
Netback before hedging ($ millions)	$ 143.7	$ 30.3	$ 174.0
Netback after hedging ($ millions)	$ 123.6	$ 31.0	$ 154.6

	Three months ended March 31, 2020		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	59,226 BOE/day	233,898 Mcfe/day	98,209 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 44.46	$ 2.16	$ 31.96
Royalties and production taxes	(11.94)	(0.40)	(8.16)
Operating expenses	(13.35)	(0.33)	(8.84)
Transportation costs	(2.92)	(0.92)	(3.95)
Netback before hedging	$ 16.25	$ 0.51	$ 11.01
Cash hedging gains/(losses)	6.12	—	3.69
Netback after hedging	$ 22.37	$ 0.51	$ 14.70
Netback before hedging ($ millions)	$ 87.6	$ 10.8	$ 98.4
Netback after hedging ($ millions)	$ 120.6	$ 10.8	$ 131.4

(1) See “Non-GAAP Measures” in this MD&A

Total netbacks before and after hedging for the three months ended March 31, 2021, were higher compared to the same period in 2020, primarily due to higher realized prices partially offset by lower production.

For the three months ended March 31, 2021, our crude oil properties accounted for 83% of our total netback before hedging, compared to 89% during the same period in 2020.

General and Administrative ("G&A") Expenses

Total G&A expenses include share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans"). See Note 13 and Note 16(b) to the Interim Financial Statements for further details.

	Three months ended March 31,	
($ millions)	2021	2020
Cash:		
G&A expense	$ 13.1	$ 12.2
Share-based compensation expense	2.8	(2.7)
Non-Cash:		
Share-based compensation expense	1.1	7.7
Equity swap loss/(gain)	(0.6)	1.9
G&A expense	(0.1)	0.1
Total G&A expenses	$ 16.3	$ 19.2

	Three months ended March 31,	
(Per BOE)	2021	2020
Cash:		
G&A expense	$ 1.59	$ 1.37
Share-based compensation expense	0.33	(0.31)
Non-Cash:		
Share-based compensation expense	0.14	0.86
Equity swap loss/(gain)	(0.07)	0.21
G&A expense	(0.01)	0.01
Total G&A expenses	$ 1.98	$ 2.14

Cash G&A expenses for the three months ended March 31, 2021 were $13.1 million or $1.59/BOE, compared to $12.2 million, or $1.37/BOE, for the same period in 2020. Cash G&A expenses were slightly higher compared to the same period in 2020, due to timing of expenses and increased on a per BOE basis due to lower production.

During the first quarter of 2021, we reported a cash SBC expense of $2.8 million compared to a recovery of $2.7 million for the same period in 2020. The expense was due to the increase in our share price on our outstanding Director Deferred Share Units. Non-cash SBC expense for the three months ended March 31, 2021 was $1.1 million, or $0.14/BOE, compared to an expense of $7.7 million, or $0.86/BOE, during the same period in 2020 as a result of lower performance multipliers on our outstanding Performance Share Units ("PSUs").

We have hedges in place on a portion of the outstanding cash-settled grants under our LTI plans. In the first quarter of 2021, we recorded a mark-to-market gain of $0.6 million on these contracts, compared to a loss of $1.9 million for the same period in 2020.

We expect cash G&A expenses of $1.25/BOE in 2021, a decrease from the first quarter of 2021 primarily due to an increase in production as a result of the Bruin and Hess acquisitions.

Interest Expense

For the three months ended March 31, 2021, we recorded total interest expense of $6.8 million, compared to $8.9 million for the same period in 2020. The decrease in interest expense was primarily due to the repayment of a portion of our 2009 and 2012 senior notes during the second quarter of 2020 and the impact of a stronger Canadian dollar on our U.S. dollar denominated interest expense. The decrease was partially offset by additional interest expense on our US$400 million term loan, which was used to fund a portion of the Bruin Acquisition.

At March 31, 2021, approximately 49% of our debt was based on fixed interest rates and 51% on floating interest rates with weighted average interest rates of 4.4% and 1.8%, respectively. See Note 9 to the Interim Financial Statements for further details.

Foreign Exchange

($ millions)	Three months ended March 31, 2021	2020
Realized foreign exchange (gain)/loss:		
Foreign exchange (gain)/loss on settlements	$ 0.3	$ (0.1)
Translation of U.S. dollar cash held in Canada (gain)/loss	(0.5)	(3.1)
Unrealized foreign exchange (gain)/loss	0.3	(2.4)
Total foreign exchange (gain)/loss	$ 0.1	$ (5.6)
USD/CDN average exchange rate	1.27	1.34
USD/CDN period end exchange rate	1.26	1.41

For the three months ended March 31, 2021, we recorded a foreign exchange loss of $0.1 million compared to a gain of $5.6 million for the same period in 2020. Realized foreign exchange gains and losses relate primarily to day-to-day transactions recorded in foreign currencies and 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, 2021, US$385.4 million of senior notes outstanding and the US$400 million term loan were designated as net investment hedges. For the three months ended March 31, 2020, Other Comprehensive Income/(Loss) included an unrealized gain of $8.5 million, on our U.S. dollar denominated senior notes and term loan.

Capital Investment

($ millions)	Three months ended March 31, 2021	2020
Capital spending[(1)]	$ 65.5	$ 163.6
Office capital[(1)]	0.4	1.9
Sub-total	65.9	165.5
Property and land acquisitions	$ 3.4	$ 2.3
Bruin Acquisition[(2)]	625.2	—
Property divestments	(5.0)	(5.6)
Sub-total	623.6	(3.3)
Total	$ 689.5	$ 162.2

(1) Excludes changes in non-cash investing working capital. See Note 18(c) to the Interim Financial Statements for further details.
(2) Excludes asset retirement obligations assumed with the Bruin Acquisition.

Capital spending for the three months ended March 31, 2021 totaled $65.5 million compared to $163.6 million for the same period in 2020. During the first quarter of 2021, we spent $55.8 million on our U.S. crude oil properties, $5.0 million on our Marcellus natural gas assets and $2.9 million on our Canadian waterflood properties.

During the first quarter of 2021, we completed the Bruin Acquisition for total cash consideration of $528.6 million with $625.2 million allocated to PP&E, excluding the assumed asset retirement obligation. Additionally, we completed $3.4 million in property and land acquisitions compared to $2.3 million during the same period in 2020. Property divestments for the three months ended March 31, 2021 were $5.0 million compared to $5.6 million for the same period in 2020.

Subsequent to the quarter, we entered into a purchase and sale agreement to acquire certain assets in the Williston Basin from Hess for total cash consideration of US$312.0 million, subject to certain customary purchase price adjustments. The Hess Acquisition closed on April 30, 2021.

Our capital spending guidance range for 2021 is $360 to $400 million**.**

Depletion, Depreciation and Accretion (“DD&A”)

($ millions, except per BOE amounts)	Three months ended March 31, 2021	2020
DD&A expense	$ 46.5	$ 95.2
Per BOE	$ 5.47	$ 10.65

DD&A of PP&E is recognized using the unit-of-production method based on proved reserves. For the three months ended March 31, 2021, DD&A expense decreased compared to the same period in 2020 mainly due to the impact of previous PP&E impairments.

Impairment

PP&E

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves using SEC constant prices ("Standardized Measure"). 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. See Note 7(b) to the Interim Financial Statements for trailing twelve month prices.

Trailing twelve month average crude oil and natural gas prices declined throughout 2020 and improved in the first quarter of 2021. For the three months ended March 31, 2021, we recorded a non-cash PP&E impairment of $4.3 million related to our Canadian assets. There was no impairment recorded for the same period in 2020. We requested and received a temporary exemption from the SEC to exclude the properties acquired in the Bruin Acquisition in the U.S. full cost ceiling test, for the first, second, third and fourth quarters of 2021.

Many factors influence the allowed ceiling value versus 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 2021, 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

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets, such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on the Condensed Consolidated Balance Sheet are based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation, using a weighted average credit-adjusted risk-free rate of 5.33%, to be $156.7 million at March 31, 2021, compared to $130.2 million at December 31, 2020, using a weighted average credit-adjusted risk-free rate of 5.35%. The increase in the net present value of our asset retirement obligation is largely due to $27.8 million of additional liability assumed in connection with the Bruin Acquisition. For the three months ended March 31, 2021, asset retirement obligation settlements were $7.1 million, compared to $10.8 million during the same period in 2020.

For the three months ended March 31, 2021, Enerplus benefited from $1.7 million in provincial government grants to support the cleanup of inactive or abandoned crude oil and natural gas wells in Canada. These programs provide funding directly to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. See Note 3 and10 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. We incur lease payments related 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, 2021, our total lease liability was $36.0 million (December 31, 2020 - $36.8 million). In addition, ROU assets of $32.2 million were recorded, which equate to our lease liabilities less lease incentives (December 31, 2020 - $32.9 million). See Note 11 to the Interim Financial Statements for further details.

Income Taxes

	Three months ended March 31,	
($ millions)	2021	2020
Current tax expense/(recovery)	$ —	$ —
Deferred tax expense/(recovery)	11.0	109.4
Total tax expense/(recovery)	$ 11.0	$ 109.4

We recorded a total tax expense of $11.0 million for the period ended March 31, 2021 compared to $109.4 million for the same period in 2020. The expense in 2021 was primarily due to income reported in the U.S. compared to the same period in 2020 where we recorded a valuation allowance against a portion of our Canadian deferred income tax assets.

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. 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 $593.3 million as at March 31, 2021 (December 31, 2020 - $607 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, hedging, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant under our bank facility, term loan and senior notes, 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, 2021, our senior debt to adjusted EBITDA ratio was 1.8x and our net debt to adjusted funds flow ratio was 2.1x, which does not include the trailing adjusted funds flow associated with the Bruin Acquisition. Although it 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.

Total debt net of cash at March 31, 2021 increased to $794.2 million, compared to $376.0 million at December 31, 2020. Total debt was comprised of $983.2 million in senior notes and the term loan less $189.0 million in cash. The increase was due to funding a portion of the Bruin Acquisition using a US$400 million term loan entered into on March 10, 2021. Our next scheduled senior note repayments of US$59.6 million and US$22.0 million are due in May and June 2021, respectively, with remaining maturities extending to 2026. At March 31, 2021, we were undrawn on our bank facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 57% for the three months ended March 31, 2021, compared to 152% for the same period in 2020.

Subsequent to the quarter, the Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly, from $0.01 per share paid monthly previously. We expect to fund the increase though the incremental free cash flow generated by the business.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, decreased to $195.0 million at March 31, 2021 from $257.8 million at December 31, 2020. Our working capital varies due to the timing of the cash realization of our current assets and current liabilities, and the current level of business activity, including our capital spending program, along with commodity price volatility. At March 31, 2021 our accrued revenue receivable increased by $64.2 million as a result of higher commodity prices and production compared to December 31, 2020. We expect to finance our working capital deficit and ongoing working capital requirements through cash, adjusted funds flow and our bank facility. We have sufficient liquidity to meet our financial commitments for the near term.

During the first quarter of 2021, Enerplus acquired all the outstanding equity interests of Bruin for total cash consideration of approximately US$418 million, subject to final purchase price adjustments. Enerplus did not assume any debt of Bruin as a part of the Bruin Acquisition.

A portion of the purchase price of the Bruin Acquisition was funded with a new three-year, senior unsecured US$400 million term loan. The term loan includes financial and other covenants and pricing consistent with Enerplus' bank facility. Following the announcement of the Bruin Acquisition, Enerplus completed a bought deal equity financing, issuing 33.1 million common shares at a price of $4.00 per share for gross proceeds of $132.3 million ($127.2 million, net of issuance costs less tax). A portion of the net proceeds were used to fund the remainder of the Bruin Acquisition.

On April 8, 2021, Enerplus announced that it has entered into an agreement to acquire certain assets from Hess for total consideration of US$312 million, subject to customary purchase price adjustments. The Hess Acquisition closed on April 30, 2021 and was funded using cash and by drawing on our bank facility.

Subsequent to the quarter, we increased and extended our senior, unsecured, covenant-based bank credit facility to US$900 million from US$600 million with a maturity of October 31, 2025. As part of the extension, the company transitioned the facility to a sustainability-linked credit facility incorporating environmental, social and governance ("ESG")-linked incentive pricing terms which reduce or increase the borrowing costs by up to 5 basis points as Enerplus' sustainability performance targets ("SPT") are exceeded or missed. The SPTs are based on the following ESG goals of the company:

- **GHG Emissions:** continuous progress toward Enerplus' stated goal of a 50% reduction in corporate Scope 1 and 2 greenhouse gas emissions intensity by 2030, using 2019 as a baseline and measurement based on Enerplus' annual internal targets

- **Water Management:** achieve a 50% reduction in freshwater usage in corporate well completions by 2025 or earlier compared to 2019, with progress to be measured on an annual basis over the life of the credit facility

- **Health & Safety:** achieve and maintain a 25% reduction in the Company's Lost Time Injury Frequency, based on a trailing 3-year average, relative to a 2019 baseline

At March 31, 2021, we were in compliance with all covenants under our bank facility, the term loan 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. Our bank facility, term loan and senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at March 31, 2021:

Covenant Description		March 31, 2021
Bank Credit Facility/Term Loan:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.8x
Total debt to adjusted EBITDA (1)	4.0x	1.8x
Total debt to capitalization	55%	36%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.8x
Senior debt to consolidated present value of total proved reserves(3)	60%	42%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	21.5x

Definitions
"Senior debt" is calculated as the sum of drawn amounts on our bank credit facility, term loan, outstanding letters of credit and the principal amount of senior notes.
"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, 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, 2021 was $157.3 million and $565.7 million, respectively.
"Total debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.
"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes
(1) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.
(2) 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.
(3) 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%.Total proved reserves at December 31, 2020 has been updated for reserves acquired through the Bruin Acquisition.

Dividends

	Three months ended March 31,	
($ millions, except per share amounts)	2021	2020
Dividends to shareholders(1)	$ 7.4	$ 6.7
Per weighted average share (Basic)	$ 0.03	$ 0.03

(1) Excludes changes in non-cash financing working capital. See Note 18(b) to the Interim Financial Statements for further details.

During the three months ended March 31, 2021, we declared total dividends of $7.4 million or $0.03 per share, compared to $6.7 million or $0.03 per share for the same period in 2020. The aggregate amount of dividends paid to shareholders have increased compared to the same period in 2020 due to an increase in common shares outstanding as a result of the bought deal equity financing completed in the first quarter of 2021.

Subsequent to the quarter, our Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly, from $0.01 per share paid monthly previously. The increased quarterly dividend is payable on June 15, 2021 to all shareholders of record at the close of business on May 28, 2021. The ex-dividend date for this payment is May 27, 2021. Given the April and May dividends have already been paid or declared, the change to quarterly payments beginning in June represents an incremental dividend payment of $5.6 million in the second quarter of 2021.

The dividend is part of our current 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, 2021	2020
Share capital ($ millions)	$ 3,236.1	$ 3,097.2
Common shares outstanding (thousands)	256,751	222,564
Weighted average shares outstanding – basic (thousands)	244,066	222,357
Weighted average shares outstanding – diluted (thousands)	246,898	223,300

For the three months ended March 31, 2021, a total of 2,014,193 units vested pursuant to our treasury settled LTI plans, including the impact of performance multipliers (2020 – 2,044,718). In total, 1,140,000 shares were issued from treasury and $11.9 million was transferred from paid-in capital to share capital (2020 – 1,160,000; $13.8 million). We elected to cash settle the remaining units related to the required tax withholdings (2021 – $4.5 million, 2020 – $7.2 million).

During the three months ended March 31, 2021, we issued 33,062,500 common shares at a price of $4.00 per common share for gross proceeds of $132.3 million ($127.2 million net of issue costs less tax) pursuant to a bought deal offering under our base shelf prospectus.

As of May 5, 2021, we had 256,750,100 common shares outstanding. In addition, an aggregate of 10,883,962 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 16 to the Interim Financial Statements.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended March 31, 2021			Three months ended March 31, 2020		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	7,190	35,275	42,465	7,836	41,208	49,044
Natural gas liquids (bbls/day)	500	6,081	6,581	710	4,636	5,346
Natural gas (Mcf/day)	10,066	245,683	255,749	14,913	248,000	262,913
Total average daily production (BOE/day)	9,368	82,303	91,671	11,032	87,177	98,209
Pricing[2]						
Crude oil (per bbl)	$ 56.36	$ 69.57	$ 67.34	$ 38.78	$ 53.68	$ 51.30
Natural gas liquids (per bbl)	40.78	35.79	36.17	23.90	11.01	12.72
Natural gas (per Mcf)	3.94	3.47	3.48	2.18	2.07	2.08
Capital Expenditures						
Capital spending	$ 4.7	$ 60.8	$ 65.5	$ 11.8	$ 151.8	$ 163.6
Acquisitions	1.1	627.5	628.6	1.1	1.2	2.3
Divestments	(5.0)	—	(5.0)	—	(5.6)	(5.6)
Netback[3] Before Hedging						
Crude oil and natural gas sales	$ 42.2	$ 317.1	$ 359.3	$ 32.8	$ 252.8	$ 285.6
Royalties	(7.6)	(62.9)	(70.5)	(5.7)	(51.8)	(57.5)
Production taxes	(0.5)	(17.0)	(17.5)	(0.3)	(15.1)	(15.4)
Operating expenses	(11.8)	(52.7)	(64.5)	(17.5)	(61.5)	(79.0)
Transportation costs	(2.1)	(30.7)	(32.8)	(2.1)	(33.2)	(35.3)
Netback before hedging	$ 20.2	$ 153.8	$ 174.0	$ 7.2	$ 91.2	$ 98.4
Other Expenses						
Asset impairment	$ 4.3	$ —	$ 4.3	$ —	$ —	$ —
Commodity derivative instruments loss/(gain)	69.8	—	69.8	(131.3)	—	(131.3)
Total G&A (including SBC)	6.7	9.6	16.3	(0.3)	19.5	19.2

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Crude Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2021				
First Quarter	$ 288.8	$ 14.7	$ 0.06	$ 0.06
Total 2021	$ 288.8	$ 14.7	$ 0.06	$ 0.06
2020				
Fourth Quarter	$ 195.1	$ (204.2)	$ (0.92)	$ (0.92)
Third Quarter	191.9	(112.8)	(0.51)	(0.51)
Second Quarter	122.1	(609.3)	(2.74)	(2.74)
First Quarter	228.1	2.9	0.01	0.01
Total 2020	$ 737.2	$ (923.4)	$ (4.15)	$ (4.15)
2019				
Fourth Quarter	$ 327.0	$ (429.1)	$ (1.93)	$ (1.93)
Third Quarter	318.9	65.1	0.28	0.28
Second Quarter	321.4	85.1	0.36	0.36
First Quarter	287.5	19.2	0.08	0.08
Total 2019	$ 1,254.8	$ (259.7)	$ (1.12)	$ (1.12)

Crude oil and natural gas sales, net of royalties, increased to $288.8 million during the first quarter of 2021 compared to $195.1 million in the fourth quarter of 2020. The increase in crude oil and natural gas sales, net of royalties, was a result of improved realized pricing in the first quarter of 2021 and increased production, when compared to the fourth quarter of 2020. We reported net income of $14.7 million during the first quarter of 2021 compared to a net loss of $204.2 million during the fourth quarter of 2020. The net loss in the fourth quarter of 2020 was due to non-cash PP&E impairments of $311.2 million, compared to impairment of $4.3 million during the first quarter of 2021.

Crude oil and natural gas sales, net of royalties, decreased in 2020 compared to 2019 due to lower commodity prices, and decreased production. We reported a net loss in 2020 due to a $994.8 million non-cash PP&E impairment and a $202.8 million non-cash goodwill impairment.

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, 2020, other than as described in Note 3 to the Interim Financial Statements, "Accounting Policy Changes".

2021 GUIDANCE

The following table summarizes our 2021 guidance and includes an eight month contribution from the Hess Acquisition, which closed April 30, 2021.

Summary of 2021 Annual Expectations(1)(2)	Target Annual Results
Capital spending	$360 - $400 million
Average annual production	111,000 - 115,000 BOE/day
Average annual crude oil and natural gas liquids production	68,500 - 71,500 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	26%
Operating expenses	$8.25/BOE
Transportation costs	$3.85/BOE
Cash G&A expenses	$1.25/BOE

Summary of 2021 Annual Expectations(1)(2)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(3.25)/bbl
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.55)/Mcf

(1) Guidance is based on the continued operation of DAPL.
(2) Excluding transportation costs.

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities:

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating operating performance of crude oil and natural gas assets. Netback is calculated as crude oil and natural gas sales less royalties, production taxes, operating expenses and transportation costs.

Calculation of Netback	Three months ended March 31,	
($ millions)	2021	2020
Crude oil and natural gas sales	$ 359.3	$ 285.6
Less:		
Royalties	(70.5)	(57.5)
Production taxes	(17.5)	(15.4)
Operating expenses	(64.5)	(79.0)
Transportation costs	(32.8)	(35.3)
Netback before hedging	$ 174.0	$ 98.4
Cash gains/(losses) on derivative instruments	(19.4)	33.0
Netback after hedging	$ 154.6	$ 131.4

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

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	Three months ended March 31,	
($ millions)	2021	2020
Cash flow from operating activities	$ 37.2	$ 122.7
Asset retirement obligation expenditures	7.1	10.8
Changes in non-cash operating working capital	83.7	(20.3)
Adjusted funds flow	$ 128.0	$ 113.2

"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.

Calculation of Free Cash Flow	Three months ended March 31,	
($ millions)	2021	2020
Adjusted funds flow	$ 128.0	$ 113.2
Capital spending	(65.5)	(163.6)
Free cash flow	$ 62.5	$ (50.4)

"Adjusted net income/(loss)" is used by Enerplus and is useful to investors and securities analysts in evaluating the financial performance of the Company by understanding the impact of certain non-cash items and other items that the Company considers appropriate to adjust given the irregular nature and relevance to comparable companies. Adjusted net income/(loss) is calculated as net income/(loss) adjusted for unrealized derivative instrument gain/loss, asset impairment, unrealized foreign exchange gain/loss, the tax effect of these items, and the valuation allowance on our deferred income tax assets. No income tax rate adjustment on deferred taxes or goodwill impairment were recorded for the three months ended March 31, 2021 and 2020.

Calculation of Adjusted Net Income	Three months ended March 31,	
($ millions)	2021	2020
Net income/(loss)	$ 14.7	$ 2.9
Unrealized derivative instrument (gain)/loss	49.8	(96.4)
Asset impairment	4.3	—
Unrealized foreign exchange (gain)/loss	0.3	(2.4)
Tax effect on above items	(12.8)	23.4
Valuation allowance on deferred taxes	—	93.6
Adjusted net income/(loss)	$ 56.3	$ 21.1

"Total debt net of cash" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. Total debt net of cash is calculated as senior notes plus term loan plus any outstanding bank credit facility balance, minus cash and cash equivalents.

"**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 total debt net of cash divided by trailing twelve months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") and is not a debt covenant.

"**Adjusted payout ratio**" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. We calculate adjusted payout ratio as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Three months ended March 31,**	
($ millions)	**2021**	**2020**
Dividends	$ 7.4	$ 6.7
Capital and office expenditures	65.9	165.5
Sub-total	$ 73.3	$ 172.2
Adjusted funds flow	$ 128.0	$ 113.2
Adjusted payout ratio (%)	57%	152%

"Adjusted EBITDA" is used by Enerplus and its lenders to determine compliance with financial covenants under its bank credit facility and outstanding senior notes. Adjusted EBITDA is calculated on the trailing four quarters.

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	**March 31, 2021**
Net income/(loss)	$ (911.5)
Add:	
Interest	26.3
Current and deferred tax expense/(recovery)	(359.2)
DD&A and asset impairment	1,446.3
Other non-cash charges(2)	180.4
Sub-total	$ 382.3
Adjustment for material acquisitions and divestments(3)	183.4
Adjusted EBITDA	$ 565.7

(1) Balances above at March 31, 2021 include the three months ended March 31, 2021 and the second, third and fourth quarter of 2020.
(2) Includes the change in fair value of commodity derivatives and equity swaps, non-cash SBC expense, non-cash G&A expense, non-cash amortization of debt issuance costs and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than US$37.5 million as if that acquisition or disposition has been made at the beginning of the period.

In addition, the Company uses certain financial measures within the "Liquidity and Capital Resources" section of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "senior debt to consolidated present value of total proved reserves" and "adjusted EBITDA to interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility, term loan and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

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, as at March 31, 2021, 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, 2021 and ended March 31, 2021 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 benefits of the Hess Acquisition and Bruin Acquisition; expected impact of the Hess Acquisition and Bruin Acquisition on Enerplus' operations and financial results; anticipated impact of the Hess Acquisition and Bruin Acquisition on Enerplus' future costs and expenses; expectations regarding the duration and overall impact of COVID-19, expected capital spending levels in 2021 and impact thereof on our production levels and land holdings; expected production volumes and 2021 production guidance; expected operating strategy in 2021, including the effect of Enerplus’ production curtailment on its properties, operations and financial position; 2021 average production volumes, timing thereof 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 adjusted funds flow; anticipated production volumes subject to curtailment; the results from our drilling program and the timing of related production and ultimate well recoveries; oil and natural gas prices and differentials, our commodity risk management program in 2021 and expected hedging gains; expectations regarding our realized oil and natural gas prices; expected operating, transportation, cash G&A costs and share-based compensation and financing expenses; 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; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; 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, and working capital requirements; expectations regarding payment of increased dividends; expectations regarding our ability to comply with debt covenants under our bank credit facility, term loan and outstanding senior notes; expectations regarding repayment of our outstanding senior notes, including sources of funds therefor; Enerplus' costs reduction initiatives and the expected cost savings therefrom in 2021; the amount of future cash dividends that we may pay to our shareholders; and our ESG initiatives, including GHG emissions and water reduction targets for 2021.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: the benefits of the Hess Acquisition and the Bruin Acquisition; that Enerplus will realize the expected impact of the Hess Acquisition and Bruin Acquisition on Enerplus' operations and financial results and on Enerplus' future costs and expenses will be as expected and as discussed in this MD&A; that we will conduct our operations and achieve results of operations as anticipated; the continued ability to operate DAPL and lack of court order restricting its operation, that our development plans will achieve the expected results; that lack of adequate infrastructure and/or low commodity price environment will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions, including 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 continued availability and sufficiency of our adjusted funds flow and availability under our bank credit facility to fund our working capital deficiency; our ability to comply with our debt covenants; the availability of third party services; the extent of our liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; and the availability of technology and process to achieve environmental targets. In addition, our expected 2021 capital expenditures, operating strategy and 2021 guidance described in this MD&A is based on the rest of the year prices and exchange rate of: a WTI price of between US$50.00 and US$55.00/bbl, a NYMEX price of US$3.00/Mcf, a Bakken crude oil price differential of US$3.25/bbls below WTI and a USD/CDN exchange rate of 1.27. 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: failure by Enerplus to realize anticipated benefits of the Hess Acquisition or the Bruin Acquisition; continued instability, or further deterioration, in global economic and market environment, including from COVID-19; continued low commodity prices environment or further decline and/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; the legal proceedings in connection with 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; 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 facility and 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 as at December 31, 2020).*

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

(CDN$ thousands) unaudited	Note	March 31, 2021	December 31, 2020
Assets			
Current Assets			
Cash and cash equivalents		$ 189,016	$ 114,455
Accounts receivable	5	208,742	106,376
Derivative financial assets	17	4,785	3,550
Other current assets		5,918	7,137
		408,461	231,518
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	6	1,237,659	575,559
Other capital assets, net	6	19,827	19,524
Property, plant and equipment		1,257,486	595,083
Right-of-use assets	11	32,173	32,853
Deferred income tax asset	15	593,348	607,001
Total Assets		$ 2,291,468	$ 1,466,455
Liabilities			
Current liabilities			
Accounts payable	8	$ 290,808	$ 251,822
Dividends payable		2,568	2,225
Current portion of long-term debt	9	102,506	103,836
Derivative financial liabilities	17	118,944	19,261
Current portion of lease liabilities	11	13,765	13,391
		528,591	390,535
Derivative financial liabilities	17	39,720	—
Long-term debt	9	880,680	386,586
Asset retirement obligation	10	156,734	130,208
Lease liabilities	11	22,227	23,446
		1,099,361	540,240
Total Liabilities		1,627,952	930,775
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: March 31, 2021 – 257 million shares			
December 31, 2020 – 223 million shares	16	3,236,117	3,096,969
Paid-in capital		36,305	50,604
Accumulated deficit		(2,924,685)	(2,932,017)
Accumulated other comprehensive income/(loss)		315,779	320,124
		663,516	535,680
Total Liabilities & Shareholders' Equity		$ 2,291,468	$ 1,466,455

Subsequent Events 9,19

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)

(CDN$ thousands, except per share amounts) unaudited	Note	Three months ended March 31, 2021	2020
Revenues			
Crude oil and natural gas sales, net of royalties	12	$ 288,801	$ 228,127
Commodity derivative instruments gain/(loss)	17	(69,843)	131,341
		218,958	359,468
Expenses			
Operating		64,522	79,020
Transportation		32,823	35,329
Production taxes		17,452	15,444
General and administrative	13	16,272	19,185
Depletion, depreciation and accretion		46,460	95,192
Asset impairment	7	4,300	—
Interest		6,823	8,911
Foreign exchange (gain)/loss	14	122	(5,637)
Transaction costs and other expense/(income)	4	4,524	(229)
		193,298	247,215
Income/(Loss) before taxes		25,660	112,253
Current income tax expense/(recovery)	15	—	27
Deferred income tax expense/(recovery)	15	10,963	109,350
Net Income/(Loss)		$ 14,697	$ 2,876
Other Comprehensive Income/(Loss)			
Unrealized gain/(loss) on foreign currency translation		(12,867)	131,774
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt	14,17	8,522	(50,062)
Total Comprehensive Income/(Loss)		$ 10,352	$ 84,588
Net income/(Loss) per share			
Basic	16	$ 0.06	$ 0.01
Diluted	16	$ 0.06	$ 0.01

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

Condensed Consolidated Statements of Changes in Shareholders' Equity

(CDN$ thousands) unaudited	Three months ended March 31, 2021	2020
Share Capital		
Balance, beginning of period	$ 3,096,969	$ 3,088,094
Issue of shares (net of issue costs, less tax)	127,248	—
Purchase of common shares under Normal Course Issuer Bid	—	(4,731)
Share-based compensation – treasury settled	11,900	13,824
Balance, end of period	$ 3,236,117	$ 3,097,187
Paid-in Capital		
Balance, beginning of period	$ 50,604	$ 59,490
Share-based compensation – cash settled (tax withholding)	(4,491)	(7,232)
Share-based compensation – treasury settled	(11,900)	(13,824)
Share-based compensation – non-cash	2,092	5,996
Balance, end of period	$ 36,305	$ 44,430
Accumulated Deficit		
Balance, beginning of period	$ (2,932,017)	$ (1,984,365)
Purchase of common shares under Normal Course Issuer Bid	—	2,195
Net income/(loss)	14,697	2,876
Dividends declared ($0.01 per share)	(7,365)	(6,670)
Balance, end of period	$ (2,924,685)	$ (1,985,964)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of period	$ 320,124	$ 308,339
Unrealized gain/(loss) on foreign currency translation	(12,867)	131,774
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt	8,522	(50,062)
Balance, end of period	$ 315,779	$ 390,051
Total Shareholders' Equity	$ 663,516	$ 1,545,704

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

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended March 31, 2021	2020
Operating Activities			
Net income/(loss)		$ 14,697	$ 2,876
Non-cash items add/(deduct):			
Depletion, depreciation and accretion		46,460	95,192
Asset impairment	7	4,300	—
Changes in fair value of derivative instruments	17	49,842	(96,428)
Deferred income tax expense/(recovery)	15	10,963	109,350
Foreign exchange (gain)/loss on debt and working capital	14,17	319	(2,415)
Share-based compensation and general and administrative	13,16	1,842	7,755
Amortization of debt issuance costs		73	—
Translation of U.S. dollar cash held in Canada	14	(448)	(3,103)
Asset retirement obligation expenditures	10	(7,080)	(10,794)
Changes in non-cash operating working capital	18	(83,729)	20,306
Cash flow from/(used in) operating activities		37,239	122,739
Financing Activities			
Bank term loan	9	501,286	—
Proceeds from the issuance of shares	16	125,746	—
Purchase of common shares under Normal Course Issuer Bid	16	—	(2,536)
Share-based compensation – cash settled (tax withholding)	16	(4,491)	(7,232)
Dividends	16,18	(7,019)	(6,661)
Cash flow from/(used in) financing activities		615,522	(16,429)
Investing Activities			
Capital and office expenditures	18	(51,762)	(129,342)
Bruin acquisition	4	(528,597)	—
Property and land acquisitions		(3,407)	(2,256)
Property divestments		4,995	5,578
Cash flow from/(used in) investing activities		(578,771)	(126,020)
Effect of exchange rate changes on cash and cash equivalents		571	10,137
Change in cash and cash equivalents		74,561	(9,573)
Cash and cash equivalents, beginning of period		114,455	151,649
Cash and cash equivalents, end of period		**$ 189,016**	**$ 142,076**

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 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' head office is located in Calgary, Alberta, Canada.

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, 2021 and the 2020 comparative periods. 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, 2020.

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: crude oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), fair value of acquired property, plant and equipment, 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 estimates and assumptions including forecasted production volumes, forecasted operating, royalty and capital cost assumptions and assumptions around commodity pricing. When estimating the present value of future cash flows, the discount rate is not directly adjusted for the potential impacts, if any, due to climate change factors. The ultimate period in which global energy markets can fully transition from carbon-based sources to alternative energy is highly uncertain. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions.

In early March 2020, the World Health Organization declared the coronavirus ("COVID-19") outbreak a pandemic. Responses to the spread of COVID-19 have resulted in a challenging economic climate, with more volatile commodity prices and foreign exchange rates, and a decline in long-term interest rates. Although global economies have begun to recover, markets remain volatile and the timing of a full economic recovery remains uncertain. It is difficult to reliably estimate the length or severity of these developments and their financial impact. The impacts of the economic downturn to Enerplus have been considered in management's estimates described above at March 31, 2021; however, estimates made during periods of extreme volatility are subject to a higher level of uncertainty and as a result, there may be further prospective material impacts in future periods.

3) ACCOUNTING POLICY CHANGES

Recently adopted accounting standards

Government Assistance

In 2020, the Alberta, Saskatchewan, and British Columbia provincial governments created programs and provided funding to support the clean-up of inactive or abandoned crude oil and natural gas wells. Enerplus has applied for and benefited from these programs in 2021. The programs provide funding directly to oil field service contractors engaged by companies to perform abandonment, remediation, and reclamation work. Upon completion of the work, the contractors submit invoices to the provincial government for reimbursement for the pre-approved funding amounts. Enerplus recognizes the assistance once the abandonment, remediation, and reclamation work has been completed by the contractor. The benefit of the funding received by the contractor is reflected as a reduction of asset retirement obligation expenditures.

4) BUSINESS COMBINATION

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 US$465 million, subject to certain purchase price adjustments. Bruin was a private company that held oil and 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 acquisition was funded through a new three-year US$400 million term loan provided by a syndicate of financial institutions as well as a portion of the proceeds raised through a bought deal offering of common shares of the Company, which was completed on February 3, 2021. A total of 33,062,500 common shares were issued at a price of $4.00 per common share for gross proceeds of approximately $132.3 million (net proceeds of $127.2 million).

The acquisition contributed $26.2 million to crude oil and natural gas revenues net of royalties and $15.2 million to consolidated net earnings from the acquisition date to March 31, 2021. Transaction costs have been estimated at $6.0 million with $4.5 million incurred at March 31, 2021.

If the transaction had occurred on January 1, 2021, the combined entity's unaudited pro-forma crude oil and natural gas revenues net of royalties would be $360.1 million and the net loss would be $32.1 million for the three months ended March 31, 2021 (2020 – $344.1 million and a net loss of $419.7 million). The unaudited pro-forma information may not be indicative of the results that actually would have occurred if the events reflected therein had been in effect on the dates indicated or of the results that may be obtained in the future. No adjustment has been made to reflect operating synergies that may be realized as a result of the transaction.

Preliminary Purchase Price Consideration

The transaction was accounted for as an acquisition of a business under U.S. GAAP. The purchase price is measured as the fair value of the assets transferred, equity instruments issued, and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The purchase price allocation is subject to change based on information that may not yet be available. Enerplus expects the purchase price allocation to be finalized within 90-days following the acquisition date, during which time the value of the net assets and liabilities acquired may be revised as appropriate.

Preliminary Purchase Price Equation

(CDN$ thousands)	At March 10, 2021
Consideration	
Purchase Price (US$465 million)	$ 587,667
Preliminary purchase price adjustments	(59,070)
Total Consideration	$ 528,597
Fair value of identifiable assets and liabilities of Bruin	
Accounts receivable	39,174
Other current assets	1,929
Property, plant and equipment	652,920
Right of use assets	2,391
Accounts payable	(41,153)
Asset retirement obligations	(27,759)
Derivative financial liabilities	(96,514)
Lease liabilities	(2,391)
Total identifiable net assets	$ 528,597

5) ACCOUNTS RECEIVABLE

($ thousands)		March 31, 2021		December 31, 2020
Accrued revenue	$	195,163	$	93,147
Accounts receivable – trade		18,637		16,641
Allowance for doubtful accounts		(5,058)		(3,579)
Total accounts receivable, net of allowance for doubtful accounts	$	208,742	$	106,209

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

As of March 31, 2021 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
Crude oil and natural gas properties(1)	$	15,850,701	$	(14,613,042)	$	1,237,659
Other capital assets		128,832		(109,005)		19,827
Total PP&E	$	15,979,533	$	(14,722,047)	$	1,257,486

As of December 31, 2020 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
Crude oil and natural gas properties(1)	$	15,227,076	$	(14,651,517)	$	575,559
Other capital assets		127,527		(108,003)		19,524
Total PP&E	$	15,354,603	$	(14,759,520)	$	595,083

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

7) IMPAIRMENT

a) Impairment of PP&E

	Three months ended March 31,			
($ thousands)		2021		2020
Crude oil and natural gas properties:				
Canada cost centre	$	4,300	$	—
U.S. cost centre		—		—
Impairment expense	$	4,300	$	—

At March 31, 2021, we recognized $4.3 million (March 31, 2020 – nil) of PP&E impairments in our Canadian cost centre. The primary factors that affect future ceiling values include future first-day-of-the-month commodity prices, reserves revisions, capital expenditure levels and timing, acquisition and divestment activity, and production levels.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from March 31, 2020 through March 31, 2021:

Period		WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN$
Q1 2021	$	39.95	46.10	2.18	1.33
Q4 2020		39.54	45.56	2.00	1.34
Q3 2020		43.63	50.03	1.97	1.34
Q2 2020		47.37	54.94	2.08	1.34
Q1 2020		55.96	66.42	2.30	1.33

b) Ceiling Test Exemption

Pursuant to Rule 4-10(c)(4) of Regulation S-X, at each reporting period we are required to calculate the full cost ceiling test using constant prices as defined by the SEC. SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. At March 31, 2021, the calculation resulted in the net carrying costs of our crude oil and natural gas properties in our U.S. cost centre exceeding the ceiling test limitation by approximately US$265 million primarily due to the difference in the ceiling value using SEC constant prices for the assets acquired in the Bruin acquisition compared to the carrying value, which more closely represents fair market value based on forward prices. Given the short duration between closing of the Bruin acquisition and the required ceiling test calculation, we requested and received a temporary exemption from the SEC to exclude the properties acquired from Bruin in the full cost ceiling test for the first, second, third and fourth quarters of 2021.

The request for an exemption was made because we believe the fair value of the Bruin assets exceeds the full cost ceiling test and can be demonstrated to exceed its net carrying value. Our expectation of future prices is principally based on forecasted commodity prices as estimated by independent third-party reserve engineers, adjusted for basis differentials. We believe that forecasted commodity pricing reflects an independent pricing point for determining fair value. Management's internal valuation model demonstrated that the fair value of the Bruin crude oil and natural gas properties exceeded the calculated ceiling test limitation as of March 31, 2021.

We recognize that, due to the volatility associated with crude oil and natural gas prices, a downward trend in market prices could occur. If that were to occur and is deemed to be other than a temporary trend, we would assess the Bruin acquisition for impairment during the requested exemption period. Further, if we cannot demonstrate that fair value exceeds the unamortized carrying costs during the requested exemption period prior to issuance of our financial statements, we would recognize an impairment.

8) ACCOUNTS PAYABLE

($ thousands)	March 31, 2021	December 31, 2020
Accrued payables	$ 94,484	$ 107,254
Accounts payable – trade	196,324	144,568
Total accounts payable	$ 290,808	$ 251,822

9) DEBT

($ thousands)	March 31, 2021	December 31, 2020
Current:		
Senior notes	$ 102,506	$ 103,836
Long-term:		
Term Loan	499,046	—
Senior notes	381,634	386,586
Total debt	$ 983,186	$ 490,422

Upon closing the Bruin acquisition on March 10, 2021, Enerplus entered into a three-year senior unsecured US$400 million term loan. The drawn fees align with those on Enerplus' existing bank credit facility, which range between 125 and 315 basis points over banker's acceptance or LIBOR rates. The term loan includes financial and other covenants consistent with Enerplus' existing bank credit facility. The term loan ranks equally with the bank credit facility and outstanding senior notes. Debt issuance costs of $3.4 million have been netted against the term loan liability and are being amortized over the three-year term. For the three months ended March 31, 2021, total amortization of debt issuance costs was $0.1 million.

Subsequent to the quarter, Enerplus increased and extended its senior unsecured bank credit facility to US$900 million from US$600 million with a maturity of October 31, 2025 and transitioned the facility to a sustainability linked credit facility. Refer to Note 19 for further information.

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)	CDN$ Carrying Value ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	US$200,000	US$105,000	$ 131,902
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	25,124
May 15, 2012	May 15 and Nov 15	4 equal annual installments beginning May 15, 2021	4.40%	US$355,000	US$238,400	299,478
June 18, 2009	June 18	Final installment on June 18, 2021	7.97%	US$225,000	US$22,000	27,636
					Total carrying value	$ 484,140

10) ASSET RETIREMENT OBLIGATION

($ thousands)	March 31, 2021	December 31, 2020
Balance, beginning of year	$ 130,208	$ 138,049
Change in estimates	6,198	1,331
Property acquisitions and development activity	49	2,246
Bruin acquisition (Note 4)	27,759	—
Divestments	(1,915)	(1,030)
Settlements	(7,080)	(17,709)
Accretion expense	1,515	7,321
Balance, end of period	$ 156,734	$ 130,208

Enerplus has estimated the present value of its asset retirement obligation to be $156.7 million at March 31, 2021 based on a total undiscounted uninflated liability of $441.5 million (December 31, 2020 – $130.2 million and $348.4 million, respectively). The asset retirement obligation was calculated using a weighted average credit-adjusted risk-free rate of 5.33% and inflation rate of 0.9% (December 31, 2020 – 5.35% and 0.9%).

In 2021, Enerplus benefited from provincial government assistance to support the clean-up of inactive or abandoned crude oil and natural gas wells. These programs provide funding directly 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 of decommissioning costs for the Company. For the three months ended March 31, 2021, Enerplus benefited from $1.7 million in government assistance.

11) LEASES

The Company incurs lease payments 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 Sheet. Such items are charged to operating expenses and general and administrative expenses in the Condensed Consolidated Statement of Income/(Loss), unless the costs are included in the carrying amount of another asset in accordance with U.S. GAAP.

($ thousands)	March 31, 2021	December 31, 2020
Assets		
Operating right-of-use assets	$ 32,173	$ 32,853
Liabilities		
Current operating lease liabilities	$ 13,765	$ 13,391
Non-current operating lease liabilities	22,227	23,446
Total lease liabilities	$ 35,992	$ 36,837
Weighted average remaining lease term (years)		
Operating leases	3.7	3.9
Weighted average discount rate		
Operating leases	4.0%	4.2%

The components of lease expense for the three months ended March 31, 2021 are as follows:

	Three months ended March 31,	
($ thousands)	2021	2020
Operating lease cost	$ 3,606	$ 5,132
Variable lease cost	30	317
Short-term lease cost	703	5,285
Sublease income	(242)	(293)
Total	$ 4,097	$ 10,441

Maturities of lease liabilities, all of which are classified as operating leases at March 31, 2021 are as follows:

($ thousands)		Operating Leases
2021	$	11,985
2022		9,465
2023		7,321
2024		6,199
2025		1,186
After 2025		2,663
Total lease payments	$	38,819
Less imputed interest		(2,827)
Total discounted lease payments	$	35,992
Current portion of lease liabilities	$	13,765
Non-current portion of lease liabilities	$	22,227

Supplemental information related to leases is as follows:

	Three months ended March 31,			
($ thousands)		2021		2020
Cash amounts paid to settle lease liabilities:				
Operating cash flow used for operating leases	$	3,732	$	4,929
Right-of-use assets obtained/(terminated) in exchange for lease obligations:				
Operating leases	$	2,719	$	523

12) CRUDE OIL AND NATURAL GAS SALES

	Three months ended March 31,			
($ thousands)		2021		2020
Crude oil and natural gas sales	$	359,291	$	285,598
Royalties[1]		(70,490)		(57,471)
Crude oil and natural gas sales, net of royalties	$	288,801	$	228,127

(1) Royalties above do not include production taxes which are reported separately on the Condensed Consolidated Statements of Income/(Loss).

Crude oil and natural gas revenue by country and by product for the three months ended March 31, 2021 and 2020 are as follows:

Three months ended March 31, 2021 ($ thousands)		Total revenue, net of royalties[1]		Crude oil[2]		Natural gas[2]		Natural gas liquids[2]		Other(
Canada	$	34,546	$	29,053	$	3,879	$	1,314	$	300
United States		254,255		177,488		60,932		15,825		10
Total	$	288,801	$	206,541	$	64,811	$	17,139	$	310

Three months ended March 31, 2020 ($ thousands)		Total revenue, net of royalties[1]		Crude oil[2]		Natural gas[2]		Natural gas liquids[2]		Other[3]
Canada	$	27,091	$	21,989	$	3,388	$	1,094	$	620
United States		201,036		159,765		37,466		3,750		55
Total	$	228,127	$	181,754	$	40,854	$	4,844	$	675

(1) Royalties above do not include production taxes which are reported separately on the Condensed Consolidated Statements of Income/(Loss).
(2) 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.
(3) Includes third party processing income.

13) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended March 31,			
($ thousands)		2021		2020
General and administrative expense[1]	$	12,989	$	12,335
Share-based compensation expense		3,283		6,850
General and administrative expense	$	16,272	$	19,185

(1) Includes a non-cash lease credit of $115 in 2021 and an expense of $68 in 2020.

14) FOREIGN EXCHANGE

($ thousands)	Three months ended March 31, 2021	2020
Realized:		
Foreign exchange (gain)/loss	$ 251	$ (119)
Translation of U.S. dollar cash held in Canada (gain)/loss	(448)	(3,103)
Unrealized:		
Translation of working capital (gain)/loss	319	(2,415)
Foreign exchange (gain)/loss	$ 122	$ (5,637)

15) INCOME TAXES

($ thousands)	Three months ended March 31, 2021	2020
Current tax		
Canada	$ —	$ —
United States	—	27
Current tax expense/(recovery)	—	27
Deferred tax		
Canada	$ (13,022)	$ 124,481
United States	23,985	(15,131)
Deferred tax expense/(recovery)	10,963	109,350
Income tax expense/(recovery)	$ 10,963	$ 109,377

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 the following: 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 $593.3 million as at March 31, 2021 (December 31, 2020 – $607.0 million).

16) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued:	Three months ended March 31, 2021		Year ended December 31, 2020	
(thousands)	Shares	Amount	Shares	Amount
Balance, beginning of year	222,548	$ 3,096,969	221,744	$ 3,088,094
Issued/(Purchased) for cash:				
Issue of shares (net of issue costs, less tax)	33,063	127,248	—	—
Purchase of common shares under Normal Course Issuer Bid	—	—	(340)	(4,731)
Non-cash:				
Share-based compensation – treasury settled[(1)]	1,140	11,900	1,160	13,824
Cancellation of predecessor shares	—	—	(16)	(218)
Balance, end of period	256,751	$ 3,236,117	222,548	$ 3,096,969

(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, 2021 were $7.4 million (2020 – $6.7 million).

During the three months ended March 31, 2021, Enerplus issued 33,062,500 common shares at a price of $4.00 per common share for gross proceeds of $132.3 million ($127.2 million, net of $6.6 million in issue costs, less $1.5 million in tax) pursuant to a bought deal prospectus offering under its base shelf prospectus.

b) Share-based Compensation

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

($ thousands)	Three months ended March 31, 2021	2020
Cash:		
Long-term incentive plans (recovery)/expense	$ 2,749	$ (2,747)
Non-Cash:		
Long-term incentive plans expense	1,126	7,689
Equity swap (gain)/loss	(592)	1,908
Share-based compensation expense	$ 3,283	$ 6,850

i) Long-term Incentive ("LTI") Plans

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Deferred Share Unit ("DSU") and Director RSU ("DRSU") activity for the three months ended March 31, 2021:

	Cash-settled LTI plans	Equity-settled LTI plans		Total
(thousands of units)	Director Plans	PSU(1)	RSU	
Balance, beginning of year	555	2,552	1,825	4,932
Granted	259	2,100	2,100	4,459
Vested	(13)	(728)	(861)	(1,603)
Forfeited	—	—	(27)	(27)
Balance, end of period	801	3,923	3,037	7,761

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

Cash-settled LTI Plans

For the three months ended March 31, 2021, the Company recorded a cash share-based compensation expense of $2.8 million (March 31, 2020 – recovery of $ 2.7 million).

As of March 31, 2021, a liability of $5.1 million (December 31, 2020 – $2.2 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 to 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, 2021 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 5,736	$ 7,314	$ 13,050
Unrecognized share-based compensation expense	13,204	11,257	24,461
Fair value	$ 18,940	$ 18,571	$ 37,511
Weighted-average remaining contractual term (years)	1.9	1.5	

(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, 2021, $4.5 million (2020 – $7.2 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:

(thousands, except per share amounts)	Three months ended March 31, 2021	2020
Net income/(loss)	$ 14,697	$ 2,876
Weighted average shares outstanding – Basic	244,066	222,357
Dilutive impact of share-based compensation	2,832	943
Weighted average shares outstanding – Diluted	246,898	223,300
Net income/(loss) per share		
Basic	$ 0.06	$ 0.01
Diluted	$ 0.06	$ 0.01

17) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At March 31, 2021, the carrying value of cash, accounts receivable, accounts payable, and dividends payable approximated their fair value due to the short-term maturity of the instruments.

At March 31, 2021, the senior notes had a carrying value of $484.1 million and a fair value of $496.0 million (December 31, 2020 – $490.4 million and $494.1 million, respectively). The fair value of the term loan approximates its carrying value as it bears interest at floating rates and the credit spread approximates current market rates.

The fair value of derivative contracts, senior notes, and term loan 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.

The following table summarizes the income statement change in fair value for the three months ended March 31, 2021 and 2020:

Gain/(Loss) ($ thousands)	Three months ended March 31, 2021	2020	Income Statement Presentation
Equity Swaps	$ 592	$ (1,908)	G&A expense
Commodity Derivative Instruments:			
Oil	(51,669)	98,336	Commodity derivative instruments
Gas	1,235	—	
Total	$ (49,842)	$ 96,428	

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

($ thousands)	Three months ended March 31, 2021	2020
Change in fair value gain/(loss)	$ (50,434)	$ 98,336
Net realized cash gain/(loss)	(19,409)	33,005
Commodity derivative instruments gain/(loss)	$ (69,843)	$ 131,341

The following table summarizes the fair values of derivative financial instruments at the respective period ends:

	March 31, 2021						December 31, 2020					
	Assets		Liabilities				Assets		Liabilities			
($ thousands)	Current		Current		Long-term		Current		Current		Long-term	
Equity Swaps	$	—	$	3,021	$	—	$	—	$	3,613	$	—
Commodity Derivative Instruments:												
Oil		—		115,923		39,720		—		15,648		—
Gas		4,785		—		—		3,550		—		—
Total	$	4,785	$	118,944	$	39,720	$	3,550	$	19,261	$	—

On March 10, 2021, the outstanding crude oil hedges acquired with the Bruin acquisition were recorded at fair value, resulting in a liability of $96.5 million on the Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired hedges are recognized in the Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the closing date of the Bruin acquisition. For the three months ended March 31, 2021 the Company recorded a realized gain of $0.5 million on the first settlement of the Bruin hedges. The Company recognized an unrealized gain of $17.4 million in the Consolidated Statement of Income/(Loss) for the change in the fair value of the Bruin hedges during the quarter of 2021. At March 31, 2021, the fair value of the Bruin hedges was a liability of $70.9 million.

c) Risk Management

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, net of royalties and production taxes.

The following tables summarize Enerplus' price risk management positions at May 5, 2021:

Crude Oil Instruments:

Instrument Type[(1)(2)]	bbls/day	US$/bbl
Apr 1, 2021 – Jun 30, 2021		
WTI Purchased Put	20,000	40.90
WTI Sold Put	20,000	32.00
WTI Sold Call	20,000	50.72
UHC Differential Swap	1,500	(1.80)
Jul 1, 2021 – Dec 31, 2021		
WTI Purchased Put	23,000	46.39
WTI Sold Put	23,000	36.39
WTI Sold Call	23,000	56.70
UHC Differential Swap	1,500	(1.80)
Jan 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
Hedges acquired from Bruin[(3)]		
Apr 1, 2021 – Jun 30, 2021		
WTI Swap	9,750	42.16
Jul 1, 2021 – Dec 31, 2021		
WTI Swap	8,465	42.52
Jan 1, 2022 – Dec 31, 2022		
WTI Swap	3,828	42.35
Jan 1, 2023 – Oct 31, 2023		
WTI Swap	250	42.10
WTI Purchased Put	2,000	5.00
WTI Sold Call	2,000	75.00
Nov 1, 2023 – Dec 31, 2023		
WTI Purchased Put	2,000	5.00
WTI Sold Call	2,000	75.00

(1) The total average deferred premium on outstanding hedges is US$0.67/bbl from April 1, 2021 to December 31, 2021 and US$1.22/bbl from January 1, 2022 to December 31, 2022.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(2) Upon closing the Bruin acquisition, Bruin's outstanding hedges were recorded at a fair value of $96.5 million on the Condensed Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired hedges are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the date of closing the Bruin acquisition.

Natural Gas Instruments:

Instrument Type[(1)]	MMcf/day	US$/Mcf
Apr 1, 2021 – Oct 31, 2021		
NYMEX Swap	60.0	2.90
NYMEX Purchased Put	40.0	2.75
NYMEX Sold Put	40.0	2.15
NYMEX Sold Call	40.0	3.25

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

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, U.S. dollar denominated senior notes, term loan, cash deposits and working capital. Additionally, Enerplus' crude oil sales and a significant portion of its natural gas sales are based on U.S. dollar indices. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At March 31, 2021, Enerplus did not have any foreign exchange derivatives outstanding.

Enerplus may designate certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations for which the U.S. dollar is the 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 to the translation gain or loss on the net investment. At March 31, 2021, Enerplus designated all of its US$385.4 million senior notes and its US$400 million term loan as a hedge of the Company's net investment in its U.S. subsidiary. For the three months ended March 31, 2021, Enerplus recorded a $8.5 million gain, net of tax on its net investment hedge.

Interest Rate Risk:

At March 31, 2021, approximately 49% of Enerplus' debt was based on fixed interest rates and 51% on floating interest rates, with weighted average interest rates of 4.4% and 1.8%, respectively. At March 31, 2021, 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 16. Enerplus has entered into various equity swaps maturing in 2021 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 recent rapid decline 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.

Enerplus' maximum credit exposure at the balance sheet date 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 75% of Enerplus' marketing receivables were with companies considered investment grade.

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. Enerplus' allowance for doubtful accounts balance at March 31, 2021 was $5.1 million (December 31, 2020 – $3.6 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, 2021, Enerplus was in full compliance with all covenants under the bank credit facility, term loan, and outstanding senior notes. If the Company exceeds or anticipates exceeding its covenants, the Company may be required to repay, refinance, or renegotiate the terms of the debt.

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	Three months ended March 31, 2021	2020
Accounts receivable	$ (64,168)	$ 80,816
Other assets	3,148	(407)
Accounts payable	(22,708)	(60,103)
Non-cash operating activities	$ (83,729)	$ 20,306

b) Changes in Non-Cash Financing Working Capital

($ thousands)	Three months ended March 31, 2021	2020
Non-cash financing activities(1)	$ 343	$ 9

(1) Relates to changes in dividends payable and included in dividends on the Condensed Consolidated Statements of Cash Flows.

c) Changes in Non-Cash Investing Working Capital

($ thousands)	Three months ended March 31, 2021	2020
Fair value of Bruin PP&E acquired	$ 652,920	$ —
Cash paid for Bruin acquisition	(528,597)	—
Liabilities assumed	$ 124,323	$ —

($ thousands)	Three months ended March 31, 2021	2020
Non-cash investing activities, excluding Bruin acquisition(1)	$ 14,153	$ 36,195

(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) Other

($ thousands)	Three months ended March 31, 2021	2020
Cash income taxes paid/(received)	$ 5	$ (30,167)
Cash interest paid	3,217	3,287

19) SUBSEQUENT EVENTS

a) On April 8, 2021, the Company announced it had entered into a purchase agreement to acquire assets in the Williston Basin from Hess Corporation for total cash consideration of approximately US$312 million, subject to customary purchase price adjustments. The acquisition was funded using the Company's existing cash balance with the remaining portion funded through borrowing on its bank credit facility. The acquisition closed on April 30, 2021.

b) Subsequent to the quarter, Enerplus increased and extended its senior, unsecured, covenant-based bank credit facility to US$900 million from US$600 million with a maturity of October 31, 2025. As part of the extension, the company transitioned the facility to a sustainability-linked credit facility incorporating environmental, social and governance ("ESG")-linked incentive pricing terms which reduce or increase the borrowing costs by up to 5 basis points as Enerplus' sustainability performance targets ("SPT") are exceeded or missed. The SPTs are based on the following ESG goals of the company:

- **GHG Emissions**: continuous progress toward Enerplus' stated goal of a 50% reduction in corporate Scope 1 and 2 greenhouse gas emissions intensity by 2030, using 2019 as a baseline and measurement based on Enerplus' annual internal targets
- **Water Management**: achieve a 50% reduction in freshwater usage in corporate well completions by 2025 or earlier compared to 2019, with progress to be measured on an annual basis over the life of the credit facility
- **Health & Safety**: achieve and maintain a 25% reduction in the Company's Lost Time Injury Frequency, based on a trailing 3-year average, relative to a 2019 baseline

c) Subsequent to the quarter, the Company's Board of Directors approved a 10% increase to the dividend to $0.033 per share paid quarterly, from $0.01 per share paid monthly previously. The increased quarterly dividend is payable on June 15, 2021 to all shareholders of record at the close of business on May 28, 2021. The ex-dividend date for this payment is May 27, 2021.

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

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

Elliott Pew
Corporate Director
Boerne, Texas

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, U.S. Business Unit

Daniel J. Fitzgerald
Vice President, Business Development

John E. Hoffman
Vice President, Canadian Assets & 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 $US 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

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