THIRD QUARTER REPORT

enerPLUS

Nine Months Ended September 30, 2021

SELECTED FINANCIAL RESULTS	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Financial (CDN$, thousands, except ratios)				
Net Income/(Loss)	$ 112,009	$ (112,753)	$ 67,042	$ (719,200)
Adjusted Net Income/(Loss)(1)	107,358	17,705	231,541	(2,391)
Cash Flow from Operating Activities	226,642	136,987	400,783	350,286
Adjusted Funds Flow(1)	255,748	83,065	568,183	266,289
Dividends to Shareholders - Declared	9,757	6,676	28,162	20,021
Total Debt Net of Cash(1)	1,047,727	428,768	1,047,727	428,768
Capital Spending	80,241	35,345	275,675	239,054
Property and Land Acquisitions	3,848	2,388	1,041,180	8,060
Property Divestments	(271)	583	4,707	6,098
Net Debt to Adjusted Funds Flow Ratio(1)(2)	1.6x	1.0x	1.6x	1.0x
Financial per Weighted Average Shares Outstanding				
Net Income /(Loss) - Basic	$ 0.44	$ (0.51)	$ 0.27	$ (3.23)
Net Income/(Loss) - Diluted	0.43	(0.51)	0.26	(3.23)
Weighted Average Number of Shares Outstanding (000's) - Basic	256,345	222,548	252,432	222,487
Weighted Average Number of Shares Outstanding (000's) - Diluted	260,831	222,548	256,900	222,487
Selected Financial Results per BOE(3)(4)				
Crude Oil & Natural Gas Sales(5)	$ 58.47	$ 28.65	$ 50.94	$ 26.95
Royalties and Production Taxes	(15.07)	(7.36)	(12.99)	(6.94)
Commodity Derivative Instruments	(5.50)	2.36	(3.95)	4.21
Operating Expenses	(9.89)	(7.78)	(8.81)	(7.86)
Transportation Costs	(3.61)	(3.85)	(3.66)	(4.02)
Cash General and Administrative Expenses	(0.95)	(1.40)	(1.15)	(1.33)
Cash Share-Based Compensation	(0.09)	0.09	(0.20)	0.09
Interest, Foreign Exchange and Other Expenses	(0.94)	(0.82)	(1.21)	(1.14)
Current Income Tax Recovery/(Expenses)	0.10	0.02	(0.10)	0.57
Adjusted Funds Flow(1)	$ 22.52	$ 9.91	$ 18.87	$ 10.53

SELECTED OPERATING RESULTS	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Average Daily Production(4)				
Crude Oil (bbls/day)	67,910	46,082	57,486	46,098
Natural Gas Liquids (bbls/day)	10,602	6,457	9,039	5,581
Natural Gas (Mcf/day)	269,652	230,895	262,499	243,083
Total (BOE/day)	123,454	91,022	110,275	92,193
% Crude Oil and Natural Gas Liquids	64%	58%	60%	56%
Average Selling Price (4)(5)				
Crude Oil (per bbl)	$ 84.92	$ 46.43	$ 77.68	$ 43.21
Natural Gas Liquids (per bbl)	38.86	10.60	32.33	7.88
Natural Gas (per Mcf)	3.84	1.72	3.26	1.82
Net Wells Drilled	9	3	14	40

(1) These are non-GAAP measures that do not have any standardized meaning under the Company's GAAP and, therefore, 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 and Dunn County acquisitions.
(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 September 30, 2021	2020	Nine months ended September 30, 2021	2020
WTI crude oil (US$/bbl)	$ 70.56	$ 40.93	$ 64.82	$ 38.32
Brent (ICE) crude oil (US$/bbl)	73.23	43.37	67.78	42.53
NYMEX natural gas – last day (US$/Mcf)	4.01	1.98	3.18	1.88
USD/CDN average exchange rate	1.26	1.33	1.25	1.35

Share Trading Summary For the three months ended September 30, 2021	CDN[1] - ERF (CDN$)	U.S.[2] - ERF (US$)
High	$ 10.32	$ 8.14
Low	$ 3.94	$ 3.07
Close	$ 10.14	$ 8.00

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

2021 Dividends Declared per Share	CDN$	US$[1]
First Quarter Total	$ 0.03	$ 0.02
Second Quarter Total	$ 0.04	$ 0.04
Third Quarter Total	$ 0.04	$ 0.03
Total	$ 0.11	$ 0.09

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

HIGHLIGHTS: THIRD QUARTER AND 2021

- Adjusted funds flow was $255.7 million in the third quarter, which exceeded capital spending of $80.2 million, generating free cash flow of $175.5 million
- Achieved record production in the third quarter of 123,454 BOE per day, 7% higher than the prior quarter and 36% higher than the prior year period following Enerplus' strategic acquisitions in the first half of 2021
- Annual 2021 production guidance revised to 113,750 to 114,750 BOE per day due to outperformance, an increase to the guidance midpoint of 750 BOE per day despite volumes sold in connection with the Williston Basin divestment
- Continued volume growth in the fourth quarter with expected production of 124,500 to 128,500 BOE per day
- 2021 capital spending guidance now $380 million (from $360 to $400 million)
- Increased estimated 2021 free cash flow to approximately $540 million based on current forward strip commodity prices
- Net debt to adjusted funds flow ratio expected to be below 1.0x by year-end 2021
- Closed the previously announced divestment of non-strategic interests in the Williston Basin on November 2, 2021

HIGHLIGHTS: PRELIMINARY 2022 BUDGET AND INCREASED CASH RETURNS TO SHAREHOLDERS

- Expected 2022 capital spending is approximately $500 million, representing a reinvestment rate of 44% based on current forward strip commodity prices
- Expected annual 2022 production is 122,000 BOE per day, including 75,000 barrels per day of liquids
- Estimated 2022 free cash flow is $640 million based on current forward strip commodity prices
- Increased share repurchase program to $200 million, representing 7% of Enerplus' market capitalization, commencing in the fourth quarter of 2021
- Increased quarterly dividend by 8% effective with the December 15, 2021 payment

"We continue to deliver strong performance in 2021," said Ian C. Dundas, President and CEO. "We extended our core Bakken inventory through accretive acquisitions, generated over $290 million in free cash flow through the first nine months of the year and we anticipate another $250 million in free cash flow in the fourth quarter. We also expect to end the year with a net debt to adjusted funds flow ratio below one times. Looking ahead into 2022, we have a sustainable plan expected to generate meaningful free cash flow underpinned by compelling development economics. We remain committed to returning capital to shareholders which we have continued to demonstrate with today's announcement of our accelerated share repurchase program and third dividend increase in 2021."

THIRD QUARTER SUMMARY

Production in the third quarter of 2021 was 123,454 BOE per day, an increase of 36% compared to the same period a year ago, and 7% higher than the prior quarter. Crude oil and natural gas liquids production in the third quarter of 2021 was 78,512 barrels per day, an increase of 49% compared to the same period a year ago, and 10% higher than the prior quarter. The increased production compared to the same period in 2020 was primarily due to the Company's development activity in the Williston Basin and contribution from its acquisitions in 2021.

Enerplus reported third quarter 2021 net income of $112.0 million, or $0.44 per basic share, compared to a net loss of $112.8 million, or $0.51 per basic share, in the same period of the prior year due to increased production and higher commodity prices during the current period and non-cash impairments recorded in same period in 2020. Adjusted net income for the third quarter of 2021 was $107.4 million, or $0.42 per basic share, compared to $17.7 million, or $0.08 per basic share, during the same period in 2020. Adjusted net income was higher compared to the same period in 2020 due to higher commodity prices and increased production.

Enerplus' third quarter 2021 realized Bakken oil price differential was US$2.09 per barrel below WTI, compared to US$5.37 per barrel below WTI in the third quarter of 2020. Bakken differentials improved relative to the prior year period due to increased refinery demand and significant excess pipeline capacity in the region.

The Company's realized Marcellus natural gas price differential was US$0.45 per Mcf below NYMEX during the third quarter of 2021 compared to US$0.72 per Mcf below NYMEX in the third quarter of 2020. The improvement was due to increased natural gas demand and lower storage levels in 2021.

Third quarter operating expenses were $9.89 per BOE, compared to $7.78 per BOE during the same period in 2020. Operating expenses in the third quarter of 2021 increased from the prior year period due to a temporary increase in well service activity and higher water handling charges as a result of contracts with price escalators linked to WTI, as well as the increased liquids weighting in the Company's production mix.

Third quarter transportation costs were $3.61 per BOE and cash general and administrative ("G&A") expenses were $0.95 per BOE.

Enerplus recorded a current tax recovery of $1.2 million in the third quarter of 2021 related to the reduction of estimated U.S. taxes in 2021.

Exploration and development capital spending was $80.2 million in the third quarter of 2021. The Company declared $9.8 million in dividends in the quarter and repurchased 1,657,650 common shares under its normal course issuer bid ("NCIB") at an average price of $7.75 per share for total consideration of $12.9 million.

Enerplus received a $5.7 million distribution associated with a privately held investment in the third quarter which was reflected as an investing activity in the Condensed Consolidated Statements of Cash Flows.

In the third quarter Enerplus announced the divestment of its interests in the Sleeping Giant field (Montana) and the Russian Creek area (North Dakota) which closed on November 2, 2021. The total cash consideration was US$115 million, subject to customary purchase price adjustments. In addition, Enerplus will receive up to US$5 million in contingent consideration if WTI averages over US$65 per barrel in 2022 and US$60 per barrel in 2023. The production associated with Enerplus' working interest in these properties was approximately 3,000 BOE per day (76% tight oil, 1% natural gas liquids, and 23% natural gas).

At the end of the third quarter of 2021, the Company had total debt of $1,101.8 million and cash on hand of $54.1 million.

Asset Activity

Williston Basin production averaged 80,561 BOE per day (74% crude oil) during the third quarter of 2021, an increase of 65% compared to the same period a year ago, and 11% higher than the prior quarter. During the third quarter, the Company drilled eight gross operated wells (100% working interest) and brought 16 gross operated wells on production (63% average working interest).

Marcellus production averaged 192 MMcf per day during the third quarter of 2021, an increase of 4% compared to the same period in 2020, and flat with the prior quarter.

Canadian waterflood production averaged 7,562 BOE per day (94% crude oil) during the third quarter of 2021, a decrease of 2% compared to the same period in 2020, and 4% higher than the prior quarter.

2021 GUIDANCE UPDATE

Capital spending guidance was updated to $380 million, the midpoint of the previous range of $360 to $400 million.

Enerplus revised its annual 2021 production guidance to reflect outperformance in North Dakota and the Marcellus which is expected to more than offset the impact to 2021 production from its Williston Basin divestment during the fourth quarter. Total production is expected to average 113,750 to 114,750 BOE per day, including liquids production of 69,750 to 70,750 barrels per day. Fourth quarter production is expected to average 124,500 to 128,500 BOE per day, including liquids production of 80,000 to 83,000 barrels per day.

Given improved pricing year to date and ongoing commodity market strength, 2021 Bakken and Marcellus differential guidance was narrowed to US$2.00 per barrel below WTI and US$0.55 per Mcf below NYMEX, respectively.

As a result of higher third quarter operating expenses, full year 2021 operating expenses are expected to average $8.80 per BOE. Operating expenses in the fourth quarter are also expected to average $8.80 per BOE as workover activity is expected to return to normalized levels.

Cash G&A expense guidance was reduced to $1.15 per BOE.

Current income tax expense guidance was reduced to US$3 million in 2021.

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

2021 Guidance	
Capital spending	$380 million (from $360 to $400 million)
Average annual production	113,750 – 114,750 BOE/day (from 112,000 – 115,000 BOE/day)
Average annual crude oil and natural gas liquids production	69,750 – 70,750 bbls/day (from 69,500 – 71,500 bbls/day)
Average royalty and production tax rate	26%
Operating expense	$8.80/BOE (from $8.25/BOE)
Transportation expense	$3.85/BOE
Cash G&A expense	$1.15/BOE (from $1.25/BOE)
Current Income Tax expense	US$3 million (from US$5 – $7 million)

Q4 2021 Guidance	
Q4 average production	124,500 – 128,500 BOE/day
Q4 average crude oil and natural gas liquids production	80,000 – 83,000 bbls/day
Q4 operating expense	$8.80/BOE

2021 Full-Year Differential/Basis Outlook(1)	
U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(2.00)/bbl (from US$(2.35)/bbl)
Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.55)/Mcf (from US$(0.65)/Mcf)

(1) Excluding transportation costs.

PRELIMINARY 2022 BUDGET

Enerplus' preliminary 2022 capital budget is approximately $500 million, expected to result in average production of approximately 122,000 BOE per day, including 75,000 barrels per day of liquids.

Over 80% of the capital budget is expected to be allocated to North Dakota with drilling and completions activity focused on the Fort Berthold Indian Reservation, Little Knife and Murphy Creek areas.

Enerplus has secured approximately 75% of its total well cost structure in 2022 for its North Dakota program, helping to protect against inflationary pressures. Through solid execution, Enerplus expects its total wells costs in 2021 to average US$5.7 million, 10% lower than 2020 despite recent inflationary pressures. In 2022, based on the Company's current inflation expectations, Enerplus expects its total well costs in North Dakota to increase by 5% to 7% year-over-year.

The Company plans to announce its comprehensive 2022 budget in January 2022.

INCREASING CASH RETURNS TO SHAREHOLDERS

With visibility to achieving its net debt reduction target in the fourth quarter of 2021 and a strong free cash flow outlook in 2022, Enerplus' Board of Directors has approved an acceleration of the Company's return of capital plans through an expanded share repurchase program and an 8% dividend increase.

Enerplus expects to commence the execution of a $200 million share repurchase program in the fourth quarter of 2021 under its existing normal course issuer bid. Repurchases are expected to be funded out of fourth quarter 2021 and first quarter 2022 free cash flow, representing approximately 50% of forecasted free cash flow over this period based on current forward strip commodity prices. Enerplus believes the market price of its common shares are trading in a range that does not adequately reflect their underlying value based on mid-cycle commodity prices and, as a result, considers share repurchases to be a compelling investment opportunity.

Enerplus is increasing its quarterly dividend to $0.041 per share payable on December 15, 2021 to shareholders of record on November 30, 2021. This is Enerplus' third dividend increase year to date following its strategic acquisitions in North Dakota and represents a 37% increase, on an annualized basis, from the Company's dividend level at the start of the year. This dividend per share increase is expected to maintain the Company's current annual dividend expenditure at approximately $39 million following the execution of its share repurchase program. Enerplus estimates its dividend is fully funded from free cash flow down to approximately US$40 WTI.

Enerplus remains committed to returning a significant portion of free cash flow to shareholders and will continue to evaluate further cash returns in 2022. Excess free cash flow which is not returned to shareholders will be allocated to reinforcing the balance sheet.

DIRECTOR RETIREMENT

Enerplus today announced the planned retirement of Elliott Pew from its board of directors prior to year-end 2021. Mr. Pew has been a valued member of the board of directors since his appointment in 2010, including serving as Board Chair between May 2014 and May 2020.

“On behalf of the board, I would like to thank Elliott for his dedication and leadership,” said Mr. Dundas. “Elliott has been a highly-engaged director throughout his tenure and the board and company have greatly benefitted from his guidance.”

Risk Management

Enerplus’ commodity hedging positions are provided in the table below.

Enerplus’ Financial Commodity Hedging Contracts (at November 3, 2021)

	WTI Crude Oil (1)(2) (US$/bbl)			
		Oct 1, 2021 – Dec 31, 2021	**Jan 1, 2022 – Jun 30, 2022**	**Jan 1, 2022 – Dec 31, 2022**
3-way Collars				
Volume (bbls/day)		23,000	12,500	17,000
Sold Puts		$ 36.39	$ 58.00	$ 40.00
Purchased Puts		$ 46.39	$ 75.00	$ 50.00
Sold Calls		$ 56.70	$ 87.63	$ 57.91
Contracts acquired from Bruin[3]	**Oct 1, 2021 – Dec 31, 2021**	**Jan 1, 2022 – Sep 30, 2022**	**Oct 1, 2022 – Dec 31, 2022**	**Jan 1, 2023 – Dec 31, 2023**
Swaps				
Volume (bbls/day)	7,179	4,500	1,834	208
Sold Swaps	$ 43.01	$ 42.31	$ 42.65	$ 42.10
Collars				
Volume (bbls/day)	–	–	–	2,000
Purchased Puts	–	–	–	$ 5.00
Sold Calls	–	–	–	$ 75.00

	NYMEX Natural Gas (US$/Mcf)		
	Oct 1, 2021 – Oct 31, 2021	**Nov 1, 2021 – Mar 31, 2022**	**Apr 1, 2022 – Oct 31, 2022**
Swaps			
Volume (mcf/day)	60,000	–	40,000
Sold Swaps	$ 2.90	–	$ 3.40
Collars			
Volume (mcf/day)	40,000	40,000	–
Sold Puts	$ 2.15	–	–
Purchased Puts	$ 2.75	$ 3.43	–
Sold Calls	$ 3.25	$ 6.00	–

(1) The total average deferred premium spent on outstanding contracts is US$0.87/bbl from October 1, 2021 - December 31, 2021 and US$1.29/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 contracts were recorded at a fair value liability of $96.5 million. At September 30, 2021, the fair value of the Bruin contracts was a liability of $82.6 million, including $42.6 million of the original $96.5 million liability acquired. For the three and nine months ended September 30, 2021 we recorded a realized loss of $10.3 million and $11.9 million, respectively, on the settlement of the Bruin contracts. In addition, we recognized an unrealized loss of $4.6 million and $40.0 million, respectively, for the change in the fair value of the Bruin contracts over the same periods. See Note 17 to the Q3 2021 Financial Statements for further detail.

Q3 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 Friday, November 5, 2021 to discuss these results. Details of the conference call are as follows:

Date: Friday, November 5, 2021
Time: 9:00 AM MT (11:00 AM ET)
Dial-In: 587-880-2171 (Alberta)
1-888-390-0546 (Toll Free)
Conference ID: 22989526
Audiocast: https://produceredition.webcasts.com/starthere.jsp?ei=1501958&tp_key=661d09508f

To ensure timely participation in the conference call, callers are encouraged to dial in 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: 989526 #

Summary of Average Daily Production(1)

	Three months ended September 30, 2021					Nine months ended September 30, 2021				
	Williston Basin	Marcellus	Canadian Waterfloods	Other(2)	Total	Williston Basin	Marcellus	Canadian Waterfloods	Other(2)	Total
Tight oil (bbl/d)	59,338	—	—	1,375	60,712	48,999	—	—	1,356	50,355
Light & medium oil (bbl/d)	—	—	3,012	35	3,048	—	—	2,984	55	3,039
Heavy oil (bbl/d)	—	—	4,118	31	4,150	—	—	4,070	22	4,092
Total crude oil (bbl/d)	**59,338**	—	**7,131**	**1,441**	**67,910**	48,999	—	7,054	1,433	57,486
Natural gas liquids (bbl/d)	9,991	—	107	504	10,602	8,429	—	86	524	9,039
Shale gas (Mcf/d)	67,394	192,427	—	1,371	261,192	56,723	195,963	—	1,348	254,034
Conventional natural gas (Mcf/d)	—	—	1,945	6,514	8,460	—	—	1,476	6,989	8,465
Total natrual gas (Mcf/d)	**67,394**	**192,427**	**1,945**	**7,886**	**269,652**	56,723	195,963	1,476	8,337	262,499
Total Production (BOE/day)	**80,561**	**32,071**	**7,562**	**3,260**	**123,454**	**66,881**	**32,660**	**7,386**	**3,347**	**110,275**

(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 September 30, 2021				Nine months ended September 30, 2021			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	8	8.0	14	0.3	12	12.0	14	0.3
Marcellus	—	—	21	1.1	—	—	49	1.8
Canadian Waterfloods	—	—	—	—	—	—	—	—
Other(2)	—	—	—	—	—	—	2	0.3
Total	**8**	**8.0**	**35**	**1.4**	**12**	**12.0**	**65**	**2.5**

(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 September 30, 2021				Nine months ended September 30, 2021			
	Operated		Non Operated		Operated		Non Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Williston Basin	16	10.1	—	—	42	32.1	1	0.4
Marcellus	—	—	18	0.3	—	—	54	2.1
Canadian Waterfloods	—	—	—	—	—	—	—	—
Other(2)	—	—	—	—	3	2.6	2	0.3
Total	**16**	**10.1**	**18**	**0.3**	**45**	**34.7**	**57**	**2.8**

(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 statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "believes", "plans", "ongoing", "may", "will", "project", "budget", "strategy", and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this news release contains forward-looking information pertaining to the following: expected impact of the Dunn County acquisition, the Bruin acquisition and the Montana and Russian Creek divestments on Enerplus' operations and financial results, including expected free cash flow in 2021, 2022 and beyond; updated 2021 and future capital spending guidance, and expected capital spending levels in 2022 and the future, and the impact thereof on our production levels and land holdings; expected capital spending for 2022 and allocation amongst drilling completions activity; expected production volumes in fourth quarter and in 2022, and updated 2021 and future production guidance; the intention to commence a share repurchase program, including the timing and terms thereof and quantity of purchases of common shares thereunder; expectations of funding the increase in dividends and share repurchase program from free cash flow; expected operating strategy in 2021; anticipated total well costs in 2021 and the future and the expected impact of its anticipated 2022 well cost structure; expectations regarding generation of free cash flow; 2021 average production volumes, timing thereof and the anticipated production mix; the results from our drilling program and the timing of related production and ultimate well recoveries; oil and natural gas prices and differentials and expectations regarding the market environment, commodity risk management program in 2021 and expected hedging gains; updated 2021 Marcellus and Bakken differential guidance; expectations regarding realized oil and natural gas prices; expected operating, transportation, cash G&A costs and share-based compensation and financing expenses; updated 2021 operating expense, cash G&A cost and current tax expense guidance; future royalty and production and U.S. cash taxes; deferred income taxes, tax pools and the time at which Canadian cash taxes may be paid; future debt and working capital levels and net debt to adjusted funds-flow ratio, financial capacity, liquidity and capital resources to fund capital spending, and working capital requirements and deficits; expectations regarding our ability to comply with or renegotiate debt covenants under the Bank Credit Facility, term loan and outstanding senior notes; Enerplus' costs reduction initiatives; expectations regarding payment of increased dividends and maintenance of current annual dividend expenditures; and the amount of future cash dividends that may be paid to shareholders.

The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: the benefits of the Dunn County acquisition, the Bruin acquisition and the Montana and Russian Creek divestments; that Enerplus will realize the expected impact of the Dunn County acquisition, the Bruin acquisition and the Montana and Russian Creek divestments on Enerplus' operations and financial results and that Enerplus' future costs and expenses will be as expected and as discussed in this news release; that we will conduct our operations and achieve results of operations as anticipated; the continued operation of the Dakota Access Pipeline; that 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 and anticipated commodity prices, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions, the impact of inflation, weather conditions, storage fundamentals and expectations regarding the duration and overall impact of COVID-19; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the ability to fund increased dividend payments and the share repurchase program from free cash flow as expected and discussed in this news release; the continued availability and sufficiency of our adjusted funds flow and availability under Enerplus' Bank

Credit Facility to fund working capital deficiency; Enerplus' ability to comply with its debt covenants; the availability of third party services; expected transportation expenses; the extent of liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; factors used to assess the realizability of our deferred income tax assets; and the availability of technology and process to achieve environmental targets. In addition, Enerplus' 2021 outlook contained in this news release is based on the following prices: a US$68.76/bbl WTI, US$3.87/Mcf NYMEX, and a USD/CDN exchange rate of 1.25. Furthermore, in addition, Enerplus' preliminary 2022 outlook contained in this news release is based on the following: a WTI price of US$72.88/bbl, a NYMEX price of US$4.44/Mcf and a USD/CDN exchange rate of 1.24. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. Current conditions, economic and otherwise, render assumptions, although reasonable when made, subject to greater uncertainty.

The forward-looking information included in this news release is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: failure by Enerplus to realize anticipated benefits of the Dunn County acquisition, the Bruin acquisition or the Montana and Russian Creek divestments; continued instability, or further deterioration, in global economic and market environment, including from COVID-19 and/or inflation; the continued high commodity price environment, or further volatility or a decline in commodity prices; changes in realized prices of Enerplus' products from those currently anticipated; changes in the demand for or supply of Enerplus' products; unanticipated operating results, results from our capital spending activities or production declines; legal proceedings or other events inhibiting or preventing operation of the Dakota Access Pipeline; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; risks associated with the realization of our deferred income tax assets; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under the Bank Credit Facility, term loan and/or outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; changes in law or government programs or policies in Canada or the United States; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in this news release, the Annual Information Form, the Annual MD&A and Form 40-F as at December 31, 2020).

The forward-looking information contained in this news release speaks only as of the date of this news release. Enerplus does not undertake any obligation to publicly update or revise any forward-looking information contained herein, except as required by applicable laws.

NON-GAAP MEASURES

In this news release, Enerplus uses the terms "adjusted funds flow", "adjusted net income", "free cash flow", "reinvestment rate", "total debt net of cash" 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, goodwill 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. "Reinvestment rate" is calculated as exploration and development capital spending divided by adjusted funds flow. "Total debt net of cash" is calculated as senior notes plus term loan plus outstanding bank credit facility balance, minus cash and cash equivalents". "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", "reinvestment rate", "total debt net of cash" 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 Third 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 November 4, 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 and nine months ended September 30, 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.

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.

For more details on our acquisition (the "Dunn County Acquisition") of certain assets in the Williston Basin ("Dunn County") from Hess Bakken Investments II, LLC ("Hess"), see Note 4 to the Interim Financial Statements as well as the material change report dated April 16, 2021 available under Enerplus' SEDAR profile at www.sedar.com and Enerplus' EDGAR profile under Form 6-K at www.sec.gov.

OVERVIEW

Production during the third quarter of 2021 averaged 123,454 BOE/day, an increase of 7% compared to average production of 115,351 BOE/day in the second quarter of 2021, with crude oil and natural gas liquids production increasing by 10% over the same period. The increase in production was due to 10 net operated wells coming onstream in North Dakota during the third quarter of 2021 as well as a full quarter of production from the Dunn County assets acquired on April 30, 2021. The Bruin assets acquired on March 10, 2021 also contributed meaningful production during the third quarter of 2021.

On August 30, 2021, Enerplus announced that it had entered into a definitive agreement to sell its interests in the Sleeping Giant field in Montana and the Russian Creek area in North Dakota in the Williston Basin (the “Sleeping Giant/Russian Creek Divestment”) for total cash consideration of US$115 million, subject to customary purchase price adjustments. In addition, Enerplus may receive up to US$5 million in contingent consideration if the WTI oil price averages over US$65/bbl in 2022 and US$60/bbl in 2023. The production associated with the working interest in these properties was approximately 3,000 BOE/day (76% tight oil, 1% natural gas liquids, and 23% natural gas). This disposition closed on November 2, 2021.

Including the impact of the Sleeping Giant/Russian Creek Divestment, we are revising our average annual production guidance for 2021 to 113,750 to 114,750 BOE/day, including 69,750 to 70,750 bbls/day in crude oil and natural gas liquids from 112,000 to 115,000 BOE/day, and 69,500 to 71,500 bbls/day in crude oil and natural gas liquids. For the fourth quarter of 2021, we expect average production of 124,500 to 128,500 BOE/day, including crude oil and natural gas liquids production of 80,000 to 83,000 bbls/day.

Capital spending during the third quarter of 2021 totaled $80.2 million, compared to $129.9 million during the second quarter of 2021, with the majority of the spending focused on our U.S. crude oil properties. The decrease in capital spending was due to less completions activity during the third quarter of 2021. We are revising our annual capital spending guidance for 2021 to $380 million, from a range of between $360 to $400 million.

Our realized Bakken crude oil price differential narrowed to average US$2.09/bbl below WTI during the third quarter of 2021 compared to US$2.76/bbl below WTI during the second quarter of 2021. Bakken differentials in North Dakota were supported by increased demand in the U.S. Midwest, as well as excess pipeline capacity within the basin. As a result of strong year to date realizations, we are narrowing our average annual Bakken crude oil price differential guidance to average US$2.00/bbl below WTI from US$2.35/bbl below WTI for 2021.

Our realized Marcellus natural gas price differential narrowed to average US$0.45/Mcf below NYMEX in the third quarter of 2021, compared to US$0.89/Mcf below NYMEX during the second quarter of 2021, due to increased demand and low storage levels in both the U.S. and Europe. As a result of ongoing strength in pricing, we are narrowing our annual average Marcellus natural gas price differential to average US$0.55/Mcf below NYMEX from US$0.65/Mcf below NYMEX for 2021.

Operating expenses for the third quarter of 2021 increased to $112.3 million or $9.89/BOE, compared to $88.5 million or $8.43/BOE, during the second quarter of 2021. The increase was primarily due to a temporary increase in well service activity and higher water handling charges as a result of contracts with price escalators linked to WTI crude oil prices. Operating expenses in the fourth quarter of 2021 are expected to average $8.80/BOE as workover activity is expected to return to normalized levels. As a result of higher operating expenses to date, we are increasing our annual operating expense guidance to $8.80/BOE from $8.25/BOE for 2021.

We reported net income of $112.0 million in the third quarter of 2021 compared to a net loss of $59.7 million in the second quarter of 2021. The increase in net income recognized in the third quarter of 2021 was primarily due to higher crude oil and natural gas liquids revenue as a result of higher production, higher realized prices, and a decrease in commodity derivative instrument losses compared to the second quarter of 2021.

In the third quarter of 2021 cash flow from operating activities and adjusted funds flow increased to $226.6 million and $255.7 million, respectively, compared to $136.9 million and $184.3 million in the second quarter of 2021, primarily due to higher realized prices and production.

During the quarter, we received a $5.7 million distribution associated with a privately held investment. This was reflected as an investing activity in the Condensed Consolidated Statements of Cash Flows.

At September 30, 2021, total debt net of cash was $1,047.7 million, comprised of senior notes, the sustainability linked bank credit facility (“Bank Credit Facility” or “SLL Credit Facility”) and the term loan totaling $1,101.8 million, less cash on hand of $54.1 million. Our net debt to adjusted funds flow ratio decreased to 1.6x from 2.3x in the second quarter of 2021, excluding the trailing adjusted funds flow associated with the Bruin and Dunn County acquisitions.

During the third quarter, Enerplus received approval from the Toronto Stock Exchange ("TSX") to commence a Normal Course Issuer Bid ("NCIB") to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. As a result, 1,657,650 common shares were repurchased and cancelled under the NCIB at an average price of $7.75 per share, for total consideration of $12.9 million.

Subsequent to the quarter, the Board of Directors approved increasing the dividend to $0.041 per share, to be paid quarterly, beginning December 2021. This is our third dividend increase year to date following our Bruin and Dunn County acquisitions and represents a 37% increase, on an annualized basis, from our dividend level at the start of the year. We also plan to commence the execution of a $200 million share repurchase program under the NCIB in the fourth quarter of 2021. We expect to fund the increase in dividend and share repurchase program through the free cash flow generated by the business in the fourth quarter of 2021 and first quarter of 2022.

2022 Preliminary Outlook

Our preliminary 2022 capital budget is approximately $500 million with the majority of capital allocated to our North Dakota crude oil properties. As a result, we expect average annual production of approximately 122,000 BOE/day, including 75,000 bbls/day in crude oil and natural gas liquids. The 2022 capital budget is expected to deliver robust free cash flow and we will continue to evaluate further cash returns to shareholders in 2022. Excess free cash flow which is not returned to shareholders will be allocated to reinforcing the balance sheet.

RESULTS OF OPERATIONS

Production

Daily production for the third quarter of 2021 averaged 123,454 BOE/day, an increase of 7% compared to average daily production of 115,351 BOE/day in the second quarter of 2021, with crude oil and natural gas liquids production increasing by 10% to 78,512 bbls/day over the same period. Natural gas production increased slightly to 269,652 Mcf/day, compared to 261,945 Mcf/day in the second quarter of 2021.The increases are primarily the result of production from 10 net operated wells which came onstream in North Dakota during the third quarter as well as a full quarter of production from the Dunn County Acquisition.

For the three months ended September 30, 2021, total production increased by 36% when compared to the same period in 2020. The increase in production was primarily due to production from the Bruin and Dunn County assets, acquired in the first half of 2021. Production for the three months ended September 30, 2020 was impacted by the suspension of our operated North Dakota drilling and completions program early in 2020 due to weak commodity prices.

For the nine months ended September 30, 2021, total production increased by 20% compared to the same period in 2020. The increase was mainly due to additional production from the Bruin and Dunn County assets during 2021. Production for the nine months ended September 30, 2020 was also impacted by a decline in natural gas production due to limited capital activity in the Marcellus.

Our crude oil and natural gas liquids weighting for the three and nine months ended September 30, 2021 increased to 64% and 60%, respectively, from 58% and 56% over the same periods in 2020.

Average daily production volumes for the three and nine months ended September 30, 2021 and 2020 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2021**	**2020**	**% Change**	**2021**	**2020**	**% Change**
Tight oil (bbls/day)	60,712	38,683	57%	50,355	38,997	29%
Heavy oil (bbls/day)	4,150	4,117	1%	4,092	3,796	8%
Light and medium oil (bbls/day)	3,048	3,282	(7)%	3,039	3,305	(8)%
Total crude oil (bbls/day)	67,910	46,082	47%	57,486	46,098	25%
Natural gas liquids (bbls/day)	10,602	6,457	64%	9,039	5,581	62%
Shale gas (Mcf/day)	261,192	218,767	19%	254,034	230,121	10%
Conventional natural gas (Mcf/day)	8,460	12,128	(30)%	8,465	12,962	(35)%
Total natural gas (Mcf/day)	269,652	230,895	17%	262,499	243,083	8%
Total daily sales (BOE/day)	123,454	91,022	36%	110,275	92,193	20%

Including the impact of the Sleeping Giant/Russian Creek Divestment on November 2, 2021, we are revising our average annual production guidance for 2021 to 113,750 to 114,750 BOE/day, including 69,750 to 70,750 bbls/day in crude oil and natural gas liquids from 112,000 to 115,000 BOE/day, including 69,500 to 71,500 bbls/day in crude oil and natural gas liquids. For the fourth quarter of 2021, we expect average production of 124,500 to 128,500 BOE/day, including crude oil and natural gas liquids production of 80,000 to 83,000 bbls/day.

Pricing

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

Pricing (average for the period)	**Nine months ended September 30, 2021**	**Nine months ended September 30, 2020**	**Q3 2021**	**Q2 2021**	**Q1 2021**	**Q4 2020**	**Q3 2020**
Benchmarks							
WTI crude oil (US$/bbl)	$ 64.82	$ 38.32	$ 70.56	$ 66.07	$ 57.84	$ 42.66	$ 40.93
Brent (ICE) crude oil (US$/bbl)	67.78	42.53	73.23	69.02	61.10	45.24	43.37
NYMEX natural gas – last day (US$/Mcf)	3.18	1.88	4.01	2.83	2.69	2.66	1.98
USD/CDN average exchange rate	1.25	1.35	1.26	1.23	1.27	1.30	1.33
USD/CDN period end exchange rate	1.27	1.33	1.27	1.24	1.26	1.27	1.33
Enerplus selling price[1]							
Crude oil ($/bbl)	$ 77.68	$ 43.21	$ 84.92	$ 76.67	$ 67.34	$ 47.95	$ 46.43
Natural gas liquids ($/bbl)	32.33	7.88	38.86	22.72	36.17	17.19	10.60
Natural gas ($/Mcf)	3.26	1.82	3.84	2.45	3.48	2.04	1.72
Average differentials							
Bakken DAPL – WTI (US$/bbl)	$ (1.24)	$ (4.70)	$ (0.68)	$ (0.40)	$ (2.63)	$ (3.45)	$ (3.40)
Brent (ICE) – WTI (US$/bbl)	2.98	4.21	2.67	2.95	3.26	2.58	2.44
MSW Edmonton – WTI (US$/bbl)	(4.14)	(5.74)	(4.07)	(3.11)	(5.24)	(4.07)	(3.51)
WCS Hardisty – WTI (US$/bbl)	(12.51)	(13.69)	(13.58)	(11.49)	(12.47)	(9.30)	(9.08)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.95)	(0.55)	(1.11)	(1.17)	(0.58)	(1.24)	(0.80)
Transco Z6 Non-New York monthly – NYMEX (US$/Mcf)	(0.43)	(0.18)	(0.73)	(0.72)	0.17	(0.83)	(0.56)
Enerplus realized differentials[1][2]							
Bakken crude oil – WTI (US$/bbl)	$ (2.59)	$ (5.02)	$ (2.09)	$ (2.76)	$ (3.12)	$ (4.82)	$ (5.37)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.49)	(0.52)	(0.45)	(0.89)	(0.15)	(1.07)	(0.72)
Canada crude oil – WTI (US$/bbl)	(12.36)	(14.04)	(12.72)	(11.46)	(12.89)	(10.18)	(9.74)

(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 third quarter of 2021, our realized crude oil sales price averaged $84.92/bbl, an increase of 11% compared to the second quarter of 2021. Benchmark WTI increased by 7% over the same period. U.S. refining demand continues to be strong due to increased mobility rates associated with the recovery from the coronavirus ("COVID-19") pandemic, while U.S domestic crude oil supply has been slow to return to pre-pandemic levels. Globally, the market balance remains in a supply and demand deficit, supported by the Organization of the Petroleum Exporting Countries Plus ("OPEC+") policy for continued production curtailments through the end of 2022.

Bakken crude oil price differentials continued to narrow due to an improving supply and demand balance and excess pipeline capacity in the region. Our realized Bakken crude oil price differential averaged US$2.09/bbl below WTI during the third quarter of 2021 compared to US$2.76/bbl below WTI during the second quarter of 2021. Given stronger year to date realizations, we are narrowing our guidance for our annual Bakken realized crude oil sales price differential to average approximately US$2.00/bbl below WTI in 2021, from US$2.35/bbl below WTI.

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 Dakota Access Pipeline ("DAPL"). Effective August 1, 2021, we increased our committed capacity to deliver crude oil from North Dakota to the U.S. Gulf coast via DAPL as a part of its broader system expansion (see "Transportation Expenses").

Our realized Canadian crude oil price differential widened by US$1.26/bbl compared to the second quarter of 2021, which was in line with changes to the underlying benchmark prices. The outlook for Canadian crude oil price differentials has improved with the recent start-up of the Enbridge Line 3 Replacement Project.

Our realized sales price for natural gas liquids averaged $38.86/bbl during the third quarter of 2021, compared to $22.72/bbl in the second quarter of 2021. Natural gas liquids prices improved during the third quarter as limited production gains were more than offset by continued demand for NGL exports from the U.S. into global markets.

NATURAL GAS

Our realized natural gas sales price averaged $3.84/Mcf during the third quarter of 2021, an increase of 57% compared to the second quarter of 2021. The NYMEX benchmark price increased by 42% over the same period. NYMEX gas prices ended the quarter very strong, due to ongoing concerns over storage levels in the U.S. and Europe heading into winter, as well as limited growth in domestic production.

Our realized Marcellus sales price differential narrowed considerably compared to the previous quarter due to much stronger spot prices in the region. Our differential in the quarter averaged US$0.45/Mcf below NYMEX compared to US$0.89/Mcf below NYMEX in the second quarter of 2021. As a result of the ongoing strength of both realized and forward pricing, we are narrowing our Marcellus differential guidance to average US$0.55/Mcf below NYMEX for 2021, from US$0.65/Mcf below NYMEX.

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, term loan and LIBOR based borrowing on our Bank Credit Facility.

Although the Canadian dollar weakened during the third quarter compared to the U.S. dollar, on a year to date basis, the Canadian dollar remained consistent at 1.27 USD/CDN. The weakening in the third quarter was in response to the spread of the COVID-19 Delta variant, resulting in concern of a slowdown in the economic recovery in Canada. The average exchange rate of 1.25 USD/CDN for the nine months ended September 30, 2021 was considerably stronger than the same period in 2020 when it averaged 1.35 USD/CDN.

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. At November 3, 2021, we have hedged 30,179 bbls/day of crude oil for the remainder of 2021 and 27,027 bbls/day during 2022. We have also hedged 100,000 Mcf/day of natural gas for the period of October 1, 2021 to October 31, 2021 and 40,000 Mcf/day for the period of November 1, 2021 to October 31, 2022. Our crude oil contracts consist of swaps and three way collars. The three way collars provide us with exposure to upward price movement; however, the sold put effectively limits the amount of downside protection we have to the difference between the strike price of the purchased and sold puts.

The following is a summary of our financial contracts in place at November 3, 2021:

		WTI Crude Oil [1][2] (US$/bbl)		
		Oct 1, 2021 – Dec 31, 2021	**Jan 1, 2022 – Jun 30, 2022**	**Jan 1, 2022 – Dec 31, 2022**
3-way Collars				
Volume (bbls/day)		23,000	12,500	17,000
Sold Puts		$ 36.39	$ 58.00	$ 40.00
Purchased Puts		$ 46.39	$ 75.00	$ 50.00
Sold Calls		$ 56.70	$ 87.63	$ 57.91
Contracts acquired from Bruin[3]	**Oct 1, 2021 – Dec 31, 2021**	**Jan 1, 2022 – Sep 30, 2022**	**Oct 1, 2022 – Dec 31, 2022**	**Jan 1, 2023 – Dec 31, 2023**
Swaps				
Volume (bbls/day)	7,179	4,500	1,834	208
Sold Swaps	$ 43.01	$ 42.31	$ 42.65	$ 42.10
Collars				
Volume (bbls/day)	–	–	–	2,000
Purchased Puts	–	–	–	$ 5.00
Sold Calls	–	–	–	$ 75.00

	NYMEX Natural Gas (US$/Mcf)		
	Oct 1, 2021 – Oct 31, 2021	**Nov 1, 2021 – Mar 31, 2022**	**Apr 1, 2022 – Oct 31, 2022**
Swaps			
Volume (mcf/day)	60,000	–	40,000
Sold Swaps	$ 2.90	–	$ 3.40
Collars			
Volume (mcf/day)	40,000	40,000	–
Sold Puts	$ 2.15	–	–
Purchased Puts	$ 2.75	$ 3.43	–
Sold Calls	$ 3.25	$ 6.00	–

(1) The total average deferred premium spent on our outstanding crude oil contracts is US$0.87/bbl from October 1, 2021 - December 31, 2021 and US$1.29/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 crude oil contracts were recorded at a fair value liability of $96.5 million. At September 30, 2021, the balance was a liability of $42.6 million on the Condensed Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired contracts 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)	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Realized gains/(losses):				
Crude oil	$ (51.2)	$ 19.7	$ (109.2)	$ 106.2
Natural gas	(11.2)	—	(9.8)	—
Total realized gains/(losses)	$ (62.4)	$ 19.7	$ (119.0)	$ 106.2
Unrealized gains/(losses):				
Crude oil	$ (1.8)	$ (18.8)	$ (200.3)	$ 15.1
Natural gas	(14.7)	—	(27.4)	—
Total unrealized gains/(losses)	$ (16.5)	$ (18.8)	$ (227.7)	$ 15.1
Total gains/(losses)	$ (78.9)	$ 0.9	$ (346.7)	$ 121.3

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2021	2020	2021	2020
Total realized gains/(losses)	$ (5.50)	$ 2.36	$ (3.95)	$ 4.21
Total unrealized gains/(losses)	(1.45)	(2.25)	(7.56)	0.60
Total gains/(losses)	$ (6.95)	$ 0.11	$ (11.51)	$ 4.81

During the three and nine months ended September 30, 2021, Enerplus realized losses of $51.2 million and $109.2 million, respectively, on our crude oil contracts compared to realized gains of $19.7 million and $106.2 million for the same periods in 2020. In the three and nine months ended September 30, 2021, realized losses of $11.2 million and $9.8 million, respectively, were recorded on our natural gas contracts. There were no natural gas derivative contracts outstanding during the same periods in 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 recorded as either an unrealized charge or gain to earnings. At September 30, 2021, the fair value of our crude oil and natural gas contracts was in a net liability position of $282.5 million. For the three and nine months ended September 30, 2021, the change in the fair value of our crude oil contracts resulted in an unrealized loss of $1.8 million and $200.3 million, respectively, compared to an unrealized loss of $18.8 million and an unrealized gain of $15.1 million during the same periods in 2020. For the three and nine months ended September 30, 2021, we recorded unrealized losses on our natural gas contracts of $14.7 million and $27.4 million, respectively. There were no natural gas derivative contracts outstanding during the same periods in 2020.

On March 10, 2021, the outstanding crude oil contracts 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 contracts are recognized in Consolidated Statement of Income/(Loss) to reflect changes in crude oil prices from the closing date of the Bruin Acquisition. At September 30, 2021, the fair value of the Bruin contracts was a liability of $82.6 million, including $42.6 million of the original $96.5 million liability acquired. For the three and nine months ended September 30, 2021 the Company recorded a realized loss of $10.3 million and $11.9 million, respectively, on the settlement of the Bruin contracts. In addition, we recognized an unrealized loss of $4.6 million and $40.0 million, respectively, for the change in the fair value of the Bruin contracts over the same periods. See Note 17 to the Interim Financial Statements for further detail.

Revenues

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Crude oil and natural gas sales	$ 664.0	$ 239.9	$ 1,533.5	$ 680.8
Royalties	(132.8)	(48.0)	(304.9)	(138.7)
Crude oil and natural gas sales, net of royalties	$ 531.2	$ 191.9	$ 1,228.6	$ 542.1

Crude oil and natural gas sales, net of royalties, for the three and nine months ended September 30, 2021 were $531.2 million and $1,228.6 million, respectively, compared to $191.9 million and $542.1 million for the same periods in 2020. The increase in revenue was primarily due to higher production as a result of the Bruin and Dunn County acquisitions in 2021 as well as higher realized prices. Revenues in 2020 were impacted by lower realized prices as a result of the demand destruction from the COVID-19 pandemic, along with a decrease in production volumes due to the suspension of our operated drilling program in North Dakota, and limited capital activity in the Marcellus.

Royalties and Production Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2021	2020	2021	2020
Royalties	$ 132.8	$ 48.0	$ 304.9	$ 138.7
Per BOE	$ 11.70	$ 5.73	$ 10.13	$ 5.49
Production taxes	$ 38.3	$ 13.6	$ 86.2	$ 36.7
Per BOE	$ 3.37	$ 1.63	$ 2.86	$ 1.45
Royalties and production taxes	$ 171.1	$ 61.6	$ 391.1	$ 175.4
Per BOE	$ 15.07	$ 7.36	$ 12.99	$ 6.94
Royalties and production taxes (% of crude oil and natural gas sales)	25.8%	25.7%	25.5%	25.8%

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 and nine months ended September 30, 2021 were $171.1 million and $391.1 million, respectively, compared to $61.6 million and $175.4 million from the same periods in 2020. Total royalties increased due to higher realized prices and higher production volumes, compared to the same periods in 2020.

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

Operating Expenses

($ millions, except per BOE amounts)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Operating expenses	$ 112.3	$ 65.1	$ 265.3	$ 198.5
Per BOE	$ 9.89	$ 7.78	$ 8.81	$ 7.86

For the three and nine months ended September 30, 2021, operating expenses were $112.3 million or $9.89/BOE and $265.3 million or $8.81/BOE, respectively, compared to $65.1 million or $7.78/BOE and $198.5 million or $7.86/BOE, for the same periods in 2020. This increase was primarily due to higher U.S. crude oil production and liquids weighting as a result of the Bruin and Dunn County acquisitions. During the third quarter of 2021, operating expenses increased due to a temporary increase in well service activity and higher water handling charges as a result of contracts with price escalators linked to WTI crude oil prices. Operating expenses were lower during the three and nine months ended September 30, 2020 primarily due to the price-related production curtailment of our highest unit expense crude oil wells, along with less well servicing activity and lower service costs.

Operating expenses in the fourth quarter of 2021 are expected to average $8.80/BOE as workover activity is expected to return to normalized levels. As a result of higher operating expenses to date, we are increasing our annual operating expense guidance to $8.80/BOE from $8.25/BOE for 2021.

Transportation Expenses

($ millions, except per BOE amounts)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Transportation expenses	$ 41.0	$ 32.2	$ 110.0	$ 101.5
Per BOE	$ 3.61	$ 3.85	$ 3.66	$ 4.02

For the three and nine months ended September 30, 2021, transportation expenses were $41.0 million or $3.61/BOE and $110.0 million or $3.66/BOE, respectively, compared to $32.2 million or $3.85/BOE and $101.5 million or $4.02/BOE for the same periods in 2020. Transportation expenses decreased on a per BOE basis for both the three and nine month periods ended September 30, 2021 compared to the same periods in 2020, partially due to the impact of a stronger Canadian dollar on our U.S. dollar denominated transportation costs.

Effective August 1, 2021, we participated in the DAPL expansion by contracting another 6,500 bbls/day of firm transportation commitments on the pipeline. The additional transportation provides access to sell a greater portion of our production at U.S. Gulf Coast and Brent pricing.

We continue to expect transportation expenses 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.

Netbacks by Property Type	Three months ended September 30, 2021 Crude Oil	Natural Gas	Total
Average Daily Production	89,860 BOE/day	201,562 Mcfe/day	123,454 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 70.23	$ 4.50	$ 58.47
Royalties and production taxes	(18.62)	(0.93)	(15.07)
Operating expenses	(13.11)	(0.21)	(9.89)
Transportation expenses	(2.89)	(0.92)	(3.61)
Netback before hedging	$ 35.61	$ 2.44	$ 29.90
Realized hedging gains/(losses)	(6.20)	(0.61)	(5.50)
Netback after hedging	$ 29.41	$ 1.83	$ 24.40
Netback before hedging ($ millions)	$ 294.4	$ 45.2	$ 339.6
Netback after hedging ($ millions)	$ 243.2	$ 34.0	$ 277.2

Netbacks by Property Type	Three months ended September 30, 2020 Crude Oil	Natural Gas	Total
Average Daily Production	57,945 BOE/day	198,464 Mcfe/day	91,022 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 39.17	$ 1.71	$ 28.65
Royalties and production taxes	(10.22)	(0.39)	(7.36)
Operating expenses	(11.05)	(0.34)	(7.78)
Transportation expenses	(2.72)	(0.97)	(3.85)
Netback before hedging	$ 15.18	$ 0.01	$ 9.66
Realized hedging gains/(losses)	3.70	—	2.36
Netback after hedging	$ 18.88	$ 0.01	$ 12.02
Netback before hedging ($ millions)	$ 80.8	$ 0.2	$ 81.0
Netback after hedging ($ millions)	$ 100.5	$ 0.2	$ 100.7

Netbacks by Property Type	Nine months ended September 30, 2021 Crude Oil	Natural Gas	Total
Average Daily Production	75,949 BOE/day	205,955 Mcfe/day	110,275 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 64.74	$ 3.40	$ 50.94
Royalties and production taxes	(17.00)	(0.69)	(12.99)
Operating expenses	(12.29)	(0.19)	(8.81)
Transportation expenses	(2.84)	(0.91)	(3.66)
Netback before hedging	$ 32.61	$ 1.61	$ 25.48
Realized hedging gains/(losses)	(5.27)	(0.17)	(3.95)
Netback after hedging	$ 27.34	$ 1.44	$ 21.53
Netback before hedging ($ millions)	$ 676.0	$ 91.1	$ 767.1
Netback after hedging ($ millions)	$ 566.8	$ 81.3	$ 648.1

Netbacks by Property Type	Nine months ended September 30, 2020 Crude Oil	Natural Gas	Total
Average Daily Production	56,433 BOE/day	214,558 Mcfe/day	92,193 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 36.87	$ 1.88	$ 26.95
Royalties and production taxes	(9.89)	(0.38)	(6.94)
Operating expenses	(11.67)	(0.31)	(7.86)
Transportation expenses	(2.94)	(0.95)	(4.02)
Netback before hedging	$ 12.37	$ 0.24	$ 8.13
Realized hedging gains/(losses)	6.87	—	4.21
Netback after hedging	$ 19.24	$ 0.24	$ 12.34
Netback before hedging ($ millions)	$ 191.3	$ 14.1	$ 205.4
Netback after hedging ($ millions)	$ 297.5	$ 14.1	$ 311.6

(1) "Netback" is a non-GAAP measure – see "Non-GAAP Measures" in this MD&A.

Total netbacks before and after hedging for the three and nine months ended September 30, 2021, were higher compared to the same periods in 2020, primarily due to higher realized prices and higher production.

For the three and nine months ended September 30, 2021, crude oil properties accounted for 87% and 88%, respectively, of total netback before hedging, compared to 100% and 93% during the same periods 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.

($ millions)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Cash:				
G&A expenses	$ 10.8	$ 11.6	$ 34.8	$ 33.3
Share-based compensation expense/(recovery)	1.0	(0.7)	6.1	(2.3)
Non-Cash:				
G&A expenses	(0.1)	(0.1)	(0.3)	(0.2)
Share-based compensation expense/(recovery)	4.2	(2.8)	5.4	8.5
Equity swap loss/(gain)	(0.3)	0.4	(1.6)	1.8
Total G&A expenses	$ 15.6	$ 8.4	$ 44.4	$ 41.1

(Per BOE)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Cash:				
G&A expenses	$ 0.95	$ 1.40	$ 1.15	$ 1.33
Share-based compensation expense/(recovery)	0.09	(0.09)	0.20	(0.09)
Non-Cash:				
G&A expenses	(0.01)	(0.01)	(0.01)	(0.01)
Share-based compensation expense/(recovery)	0.37	(0.33)	0.18	0.33
Equity swap loss/(gain)	(0.03)	0.05	(0.05)	0.07
Total G&A expenses	$ 1.37	$ 1.02	$ 1.47	$ 1.63

Cash G&A expenses for the three and nine months ended September 30, 2021 were $10.8 million or $0.95/BOE and $34.8 million or $1.15/BOE, respectively, compared to $11.6 million or $1.40/BOE and $33.3 million or $1.33/BOE for the same periods in 2020. For the three months ended September 30, 2021, cash G&A expenses were slightly lower compared to the same period in 2020 and decreased on a per BOE basis due to higher production. On a year to date basis, cash G&A expenses were higher in 2021 compared to the same period in 2020 due to a combination of 2020 salary reductions as well as COVID-19 pandemic government funding, which reimbursed qualifying Canadian employers for a portion of salaries paid. Cash G&A on a per BOE basis decreased compared to the three and nine months ended September 30, 2021, due to higher production during 2021.

Cash SBC expenses for the three and nine months ended September 30, 2021, were $1.0 million and $6.1 million, respectively, compared to a recovery of $0.7 million and $2.3 million for the same periods in 2020. The higher expense was due to the increase in our share price on our outstanding Director Deferred Share Units. Non-cash SBC expense for the three and nine months ended September 30, 2021 were $4.2 million or $0.37/BOE and $5.4 million or $0.18/BOE, respectively, compared to a recovery of $2.8 million or $0.33/BOE and an expense of $8.5 million or $0.33/BOE for the same periods in 2020. The increase in non-cash SBC expense for the three months ended September 30, 2021, was the result of more consistent 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. During the three and nine months ended September 30, 2021, we recorded a mark-to-market gain of $0.3 million and $1.6 million, respectively, as a result of the increase in our share price (2020 – loss of $0.4 million and $1.8 million, respectively).

As a result of realized cost savings to date, we are reducing our 2021 annual cash G&A guidance to $1.15/BOE from $1.25/BOE.

Interest Expense

For the three and nine months ended September 30, 2021, we recorded a total interest expense of $10.5 million and $26.8 million, respectively, compared to $6.3 million and $22.3 million for the same periods in 2020. The increase was primarily due to higher debt levels incurred to fund the Bruin and Dunn County acquisitions offset by the strengthening Canadian dollar on our U.S. dollar denominated interest expense. This increase was partially offset by the final repayment of our 2009 senior notes and the partial repayment of our 2012 senior notes during the second quarter of 2021, which carry higher interest rates than our Bank Credit Facility and Term Loan.

At September 30, 2021, approximately 35% of our debt was based on fixed interest rates and 65% on floating interest rates (December 31, 2020 – 100% fixed), with weighted average interest rates of 4.4% and 1.9%, respectively (December 31, 2020 – 4.4%). See Note 9 to the Interim Financial Statements for further details.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Realized foreign exchange (gain)/loss:				
Foreign exchange (gain)/loss on settlements	$ 0.8	$ 0.4	$ 3.9	$ 0.4
Translation of U.S. dollar cash held in Canada (gain)/loss	(0.4)	—	(2.4)	(2.7)
Unrealized foreign exchange (gain)/loss	(12.7)	0.5	(6.8)	(0.9)
Total foreign exchange (gain)/loss	$ (12.3)	$ 0.9	$ (5.3)	$ (3.2)
USD/CDN average exchange rate	1.26	1.33	1.25	1.35
USD/CDN period end exchange rate	1.27	1.33	1.27	1.33

For the three and nine months ended September 30, 2021, Enerplus recorded a foreign exchange gain of $12.3 million and $5.3 million, respectively, compared to a loss of $0.9 million and a gain of $3.2 million for the same periods in 2020. Realized foreign exchange gains and losses relate primarily to day-to-day transactions recorded in foreign currencies as well as the translation of our U.S. dollar denominated cash held in Canada, while unrealized foreign exchange gains and losses are recorded on the translation of our U.S. dollar denominated Bank Credit Facility and working capital held in Canada at each period end.

At September 30, 2021, US$303.8 million of senior notes outstanding and the US$400 million term loan were designated as net investment hedges against the investment in our U.S. subsidiary. For the three and nine months ended September 30, 2021, Other Comprehensive Income/(Loss) included an unrealized loss of $19.8 million and an unrealized gain of $3.4 million, respectively, relating to our U.S. dollar denominated senior notes and term loan. This compares to an unrealized gain of $9.9 million and an unrealized loss of $20.7 million, respectively, for the same periods in 2020.

Capital Investment

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Capital spending(1)	$ 80.2	$ 35.3	$ 275.7	$ 239.1
Office capital(1)	0.4	0.9	1.2	3.7
Line fill	6.7	—	6.7	—
Sub-total	87.3	36.2	283.6	242.8
Bruin Acquisition	$ —	$ —	$ 657.5	$ —
Dunn County Acquisition	—	—	374.8	—
Property and land acquisitions	3.8	2.4	8.9	8.1
Property divestments	0.3	(0.6)	(4.7)	(6.1)
Sub-total	4.1	1.8	1,036.5	2.0
Total	$ 91.4	$ 38.0	$ 1,320.1	$ 244.8

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

Capital spending for the three and nine months ended September 30, 2021 totaled $80.2 million and $275.7 million, respectively, compared to $35.3 million and $239.1 million for the same periods in 2020. The increase is mainly due to the timing of the suspension of operated drilling and completions activity in North Dakota during the second quarter of 2020 and the continuation of the 2021 capital program, which started in early March of 2021. Capital spending during the third quarter of 2021 included $67.3 million on our U.S. crude oil properties, $9.4 million on our Marcellus natural gas assets and $3.5 million on our Canadian waterflood properties. During the three months ended September 30, 2021, Enerplus spent $6.7 million on line fill to meet the requirements of the DAPL transportation expansion that began in August 2021.

During the nine months ended September 30, 2021, we completed the Bruin Acquisition for total cash consideration of $531.1 million, with $657.5 million allocated to PP&E, excluding the assumed asset retirement obligation. We also completed the Dunn County Acquisition for total cash consideration of $376.9 million, with $374.8 million allocated to PP&E, excluding the assumed asset retirement obligation.

Subsequent to September 30, 2021, Enerplus completed the Sleeping Giant/Russian Creek Divestment, for total consideration of US$115 million, subject to customary purchase price adjustments. Enerplus may receive up to US$5 million in contingent payments if the WTI oil price averages over US$65 per barrel in 2022 and over US$60 per barrel in 2023. The disposition closed on November 2, 2021.

We are revising our annual capital spending guidance for 2021 to $380 million, from $360 to $400 million.

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

($ millions, except per BOE amounts)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
DD&A expense	$ 102.4	$ 62.1	$ 242.7	$ 237.2
Per BOE	$ 9.01	$ 7.42	$ 8.06	$ 9.39

DD&A related to PP&E is recognized using the unit-of-production method based on proved reserves. For the three and nine months ended September 30, 2021, Enerplus recorded DD&A expense of $102.4 million and $242.7 million, respectively, compared to $62.1 million and $237.2 million for the same periods in 2020. DD&A expense on a per BOE basis for the nine months ended September 31, 2021 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 a prescribed 10 percent rate on 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(a) to the Interim Financial Statements for trailing twelve month prices.

Trailing twelve month average crude oil and natural gas prices declined throughout 2020 and have improved throughout 2021. For the three and nine months ended September 30, 2021, a non-cash PP&E impairment of nil and $4.3 million, respectively, was recorded relating to our Canadian assets. For the three and nine months ended September 30, 2020, a non-cash PP&E impairment of $256.8 million and $683.6 million was recorded (Canadian cost centre: $100.8 million, U.S. cost centre: $582.8 million).

Enerplus 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 each quarter of 2021. See Note 7(b) to the Interim Financial Statements for further details.

Many factors influence the allowed ceiling value compared to our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the remainder of 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.

Goodwill

During the second quarter of 2020, a non-cash goodwill impairment of $202.8 million was recorded relating to our U.S. reporting unit. The impairment was a result of the ongoing deterioration in macroeconomic conditions and low commodity prices due to the COVID-19 pandemic, which resulted in a reduction in the fair value of the U.S. reporting unit and a full write-off of our U.S. goodwill asset. At September 30, 2021, there was no goodwill remaining on our Condensed Consolidated Balance Sheet.

Asset Retirement Obligation ("ARO")

In connection with our operations, we incur abandonment, reclamation and remediation costs related to assets, such as surface leases, wells, facilities and pipelines. Total ARO included on the Condensed Consolidated Balance Sheet is based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate and the timing of the costs to be incurred in future periods. We have estimated the net present value of our asset retirement obligation, to be $162.1 million at September 30, 2021, compared to $130.2 million at December 31, 2020.

The increase in the net present value of our asset retirement obligation to September 30, 2021 is largely due to $35.1 million of additional liability assumed in connection with the Bruin and Dunn County acquisitions. For the three and nine months ended September 30, 2021, asset retirement obligation settlements were $2.1 million and $10.6 million, respectively, compared to $1.9 million and $13.0 million during the same periods in 2020.

In 2021, Enerplus benefited from provincial government assistance to support the cleanup of inactive or abandoned crude oil and natural gas wells. These programs provide 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 to ARO. For the three and nine months ended September 30, 2021, Enerplus benefitted from $0.3 million and $2.6 million, respectively, in government assistance. See Note 3 and 10 to the Interim Financial Statements for further details.

Leases

Enerplus recognizes right-of-use ("ROU") assets and lease liabilities on the Condensed Consolidated Balance Sheet for qualifying leases with a term greater than 12 months, including lease payments relating to office space, drilling rig commitments, vehicles, and other equipment. Total lease liabilities are based on the present value of lease payments over the lease term. Total ROU assets represent our right to use an underlying asset for the lease term. At September 30, 2021, our total lease liability was $38.7 million (December 31, 2020 - $36.8 million). In addition, ROU assets of $35.1 million were recorded, which relate 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 September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Current tax expense/(recovery)	$ (1.2)	$ (0.1)	$ 3.0	$ (14.5)
Deferred tax expense/(recovery)	39.6	(140.0)	39.5	(129.6)
Total tax expense/(recovery)	$ 38.4	$ (140.1)	$ 42.5	$ (144.1)

For the three and nine months ended September 30, 2021, we recorded a current tax recovery of $1.2 million and tax expense of $3.0 million, respectively, compared to current tax recoveries of $0.1 million and $14.5 million in 2020. The current tax recovery in the third quarter relates to the reduction of estimated U.S. taxes in 2021. We are reducing our annual current tax expense guidance to US$3 million from our previous expectations of between US$5 to US$7 million in 2021. The recovery in 2020 relates to the final U.S. Alternative Minimum Tax ("AMT") refund.

For the three and nine months ended September 30, 2021, we recorded deferred income tax expenses of $39.6 million and $39.5 million, respectively, compared to recoveries of $140.0 million and $129.6 million for the same periods in 2020. The deferred tax expense in the third quarter was primarily due to higher U.S. income in 2021. The deferred tax recovery in 2020 was primarily due to non-cash PP&E impairments recorded in both Canada and the U.S. and the valuation allowance recovery previously recorded against 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 that 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 reserves at forecast average prices and costs. There is a risk of a valuation allowance in future periods if commodity prices weaken or other evidence indicates that some of our deferred income tax assets will not be realized. See "Risk Factors and Risk Management - Risk of Impairment of Oil and Gas Properties and Deferred Tax Assets" in the Annual MD&A. For the nine months ended September 30, 2021, no valuation allowance was recorded against our U.S. and Canadian income related deferred income tax assets, however, a full valuation allowance has been recorded against our deferred income tax assets related to capital items. Our overall net deferred income tax asset was $567.6 million at September 30, 2021 (December 31, 2020 - $607.0 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 Credit 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 September 30, 2021, our senior debt to adjusted EBITDA ratio was 1.5x and our net debt to adjusted funds flow ratio was 1.6x, which does not include the trailing adjusted funds flow associated with the Bruin and Dunn County acquisitions. 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, as well as the "Non- GAAP Measures" section in this MD&A.

Total debt net of cash at September 30, 2021 increased to $1,047.7 million, compared to $376.0 million at December 31, 2020. Total debt was comprised of our senior notes, term loan and Bank Credit Facility, totaling $1,101.8 million, less cash on hand of $54.1 million. The increase was due to funding a portion of the Bruin Acquisition using a US$400 million term loan and funding the Dunn County Acquisition by drawing on our Bank Credit Facility and cash on hand. During the second quarter of 2021, we made scheduled repayments on our 2012 senior notes and the final principal repayment on our 2009 senior notes using the Bank Credit Facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital, office expenditures and line fill divided by adjusted funds flow, was 38% and 55%, respectively, for the three and nine months ended September 30, 2021, compared to 52% and 99% for the same periods in 2020.

During the third quarter, we received approval from the TSX to commence a NCIB to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. As a result, 1,657,650 common shares were repurchased and cancelled under the NCIB at an average price of $7.75 per share, for total consideration of $12.9 million. Subsequent to September 30, 2021 and up to and including November 3, 2021, we repurchased 434,700 common shares under the NCIB at an average price of $11.52 per common share, for total consideration of $5.0 million.

During the third quarter of 2021, the Board of Directors approved a 15% increase to the dividend to $0.038 per share which began September 2021. This increase is incremental to the 10% increase approved in the second quarter of 2021. Subsequent to the quarter, the Board of Directors approved increasing the dividend to $0.041 per share, to be paid quarterly, beginning December 2021. We also plan to commence the execution of a $200 million share repurchase program in the fourth quarter of 2021 under the NCIB. We expect to fund the increase in dividend and share repurchase program through the free cash flow generated by the business.

Our working capital deficiency, excluding cash and current derivative financial assets and liabilities, decreased to $249.4 million at September 30, 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. We expect to finance our working capital deficit and ongoing working capital requirements through cash, adjusted funds flow and our Bank Credit Facility. We have sufficient liquidity to meet our financial commitments for the near term.

During the second 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; and

- **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 September 30, 2021, we were in compliance with all covenants under the Bank Credit 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. Agreements relating to our Bank Credit Facility, term loan and the senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at September 30, 2021:

Covenant Description		September 30, 2021
Bank Credit Facility/Term Loan:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)	3.5x	1.5x
Total debt to adjusted EBITDA (1)	4.0x	1.5x
Total debt to capitalization	55%	39%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA (1)(2)	3.0x - 3.5x	1.5x
Senior debt to consolidated present value of total proved reserves(3)	60%	44%
	Minimum Ratio	
Adjusted EBITDA to interest (1)	4.0x	23.4x

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, accretion, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve-month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended September 30, 2021 was $270.6 million and $770.4million, 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) "Adjusted EBITDA" is a non-GAAP measure - 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 and Dunn County Acquisitions.

Dividends

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per share amounts)	2021	2020	2021	2020
Dividends to shareholders(1)	$ 9.8	$ 6.7	$ 28.2	$ 20.0
Per weighted average share (Basic)	$ 0.04	$ 0.03	$ 0.11	$ 0.09

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

During the three and nine months ended September 30, 2021, we declared total dividends of $9.8 million or $0.04 per share and $28.2 million or $0.11 per share, respectively, compared to $6.7 million or $0.03 per share, and $20.0 million or $0.09 per share for the same periods in 2020. The aggregate amount of dividends paid to shareholders has 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, as well as an increase to the dividend during the second and third quarters of 2021.

During the third quarter of 2021, the Board of Directors approved a 15% increase to the dividend to $0.038 per share paid quarterly, which began in September 2021. This increase is in addition to the 10% increase approved in the second quarter of 2021. Subsequent to the quarter, the Board of Directors approved an 8% increase to the dividend to $0.041 per share, to be paid beginning in December 2021. We expect to fund the increase through the free cash flow generated by the business. The dividend is part of our strategy to return capital to shareholders. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Nine months ended September 30,	
	2021	2020
Share capital ($ millions)	$ 3,215.2	$ 3,097.0
Common shares outstanding (thousands)	255,092	222,548
Weighted average shares outstanding – basic (thousands)	252,432	222,487
Weighted average shares outstanding – diluted (thousands)	256,900	222,487

For the nine months ended September 30, 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 nine months ended September 30, 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.

On June 23, 2021, we filed a short form base shelf prospectus (the “Shelf Prospectus”) with securities regulatory authorities in each of the provinces and territories of Canada and a Registration Statement with the U.S. Securities Exchange Commission. The Shelf Prospectus allows us to offer and issue up to an aggregate amount of $2.0 billion of common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains valid.

During the third quarter, we received approval from the TSX to commence a NCIB to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. As a result, 1,657,650 common shares were repurchased and cancelled under the NCIB at an average price of $7.75 per share, for total consideration of $12.9 million. Of the amount paid, $20.9 million was charged to share capital and $8.0 million was credited to accumulated deficit.

Subsequent to September 30, 2021 and up to and including November 3, 2021, we repurchased 434,700 common shares under the NCIB at an average price of $11.52 per common share, for total consideration of $5.0 million.

At November 3, 2021, we had 254,657,750 common shares outstanding. In addition, an aggregate of 10,996,000 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 September 30, 2021			Three months ended September 30, 2020		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	7,198	60,712	67,910	7,398	38,684	46,082
Natural gas liquids (bbls/day)	437	10,165	10,602	608	5,849	6,457
Natural gas (Mcf/day)	8,569	261,083	269,652	12,196	218,699	230,895
Total average daily production (BOE/day)	9,063	114,391	123,454	10,039	80,983	91,022
Pricing(2)						
Crude oil (per bbl)	$ 73.62	$ 86.26	$ 84.92	$ 41.21	$ 47.43	$ 46.43
Natural gas liquids (per bbl)	54.57	38.18	38.86	19.38	9.69	10.60
Natural gas (per Mcf)	4.45	3.82	3.84	2.89	1.65	1.72
Capital Investment						
Capital, office expenditures and line fill	$ 3.7	$ 83.6	$ 87.3	$ 6.1	$ 30.1	$ 36.2
Acquisitions, including property and land	0.5	3.3	3.8	0.7	1.7	2.4
Property divestments	0.3	—	0.3	—	(0.6)	(0.6)
Netback(3) Before Hedging						
Crude oil and natural gas sales	$ 54.7	$ 609.3	$ 664.0	$ 32.7	$ 207.2	$ 239.9
Royalties	(12.1)	(120.7)	(132.8)	(5.0)	(43.0)	(48.0)
Production taxes	(0.7)	(37.6)	(38.3)	(0.4)	(13.2)	(13.6)
Operating expenses	(12.8)	(99.5)	(112.3)	(13.0)	(52.1)	(65.1)
Transportation expenses	(1.9)	(39.1)	(41.0)	(2.5)	(29.7)	(32.2)
Netback before hedging	$ 27.2	$ 312.4	$ 339.6	$ 11.8	$ 69.2	$ 81.0
Other Expenses						
Asset impairment	$ —	$ —	$ —	$ 23.3	$ 233.5	$ 256.8
Commodity derivative instruments loss/(gain)	78.9	—	78.9	(0.9)	—	(0.9)
Total G&A (including SBC)	7.5	8.1	15.6	(0.3)	8.7	8.4
Current income tax expense/(recovery)	—	(1.2)	(1.2)	—	(0.1)	(0.1)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) “Netback” is a non-GAAP measure- see “Non-GAAP Measures” section in this MD&A.

($ millions, except per unit amounts)	Nine months ended September 30, 2021 Canada	U.S.	Total	Nine months ended September 30, 2020 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	7,131	50,355	57,486	7,101	38,997	46,098
Natural gas liquids (bbls/day)	461	8,578	9,039	644	4,937	5,581
Natural gas (Mcf/day)	8,734	253,765	262,499	13,137	229,946	243,083
Total average daily production (BOE/day)	9,048	101,227	110,275	9,935	82,258	92,193
Pricing[2]						
Crude oil (per bbl)	$ 65.54	$ 79.40	$ 77.68	$ 34.18	$ 44.86	$ 43.21
Natural gas liquids (per bbl)	45.13	31.64	32.33	19.70	6.34	7.88
Natural gas (per Mcf)	3.96	3.24	3.26	2.41	1.79	1.82
Capital Investment						
Capital, office expenditures and line fill	$ 13.0	$ 270.6	$ 283.6	$ 21.5	$ 221.3	$ 242.8
Acquisitions, including property and land	2.2	1,039.0	1,041.2	2.2	5.9	8.1
Property divestments	(4.7)	—	(4.7)	0.1	(6.2)	(6.1)
Netback[3] Before Hedging						
Crude oil and natural gas sales	$ 143.4	$ 1,390.1	$ 1,533.5	$ 80.2	$ 600.6	$ 680.8
Royalties	(29.8)	(275.1)	(304.9)	(12.4)	(126.3)	(138.7)
Production taxes	(1.8)	(84.4)	(86.2)	(0.6)	(36.1)	(36.7)
Operating expenses	(38.5)	(226.8)	(265.3)	(41.9)	(156.6)	(198.5)
Transportation expenses	(6.0)	(104.0)	(110.0)	(6.2)	(95.3)	(101.5)
Netback before hedging	$ 67.3	$ 699.8	$ 767.1	$ 19.1	$ 186.3	$ 205.4
Other Expenses						
Asset impairment	$ 4.3	$ —	$ 4.3	$ 100.8	$ 582.8	$ 683.6
Goodwill impairment	—	—	—	—	202.8	202.8
Commodity derivative instruments loss/(gain)	346.8	—	346.8	(121.3)	—	(121.3)
Total G&A (including SBC)	14.3	30.1	44.4	(1.0)	42.1	41.1
Current income tax expense/(recovery)	—	3.0	3.0	—	(14.5)	(14.5)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) "Netback" is a non-GAAP measure- 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	Diluted
2021				
Third Quarter	$ 531.2	$ 112.0	$ 0.44	$ 0.43
Second Quarter	408.6	(59.7)	(0.23)	(0.23)
First Quarter	288.8	14.7	0.06	0.06
Total 2021	$ 1,228.6	$ 67.0	$ 0.27	$ 0.26
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 $531.2 million during the third quarter of 2021, compared to $408.6 million during the second quarter of 2021. The increase in crude oil and natural gas sales, net of royalties, was a result of improved realized pricing and increased production during the third quarter of 2021, when compared to the second quarter of 2021. We reported net income of $112.0 million during the third quarter of 2021 compared to a net loss of $59.7 million during the second quarter of 2021. The net income in the third quarter of 2021 was primarily due to higher production and higher realized prices offset by a $78.9 million loss recorded on commodity derivative instruments, compared to a loss of $198.0 million recorded in the second 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 due to the COVID-19 pandemic. Enerplus 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

We are revising our annual capital spending guidance for 2021 to $380 million, from a range of between $360 to $400 million.

We are revising our average annual production guidance for 2021 to 113,750 to 114,750 BOE/day, including 69,750 to 70,750 BOE/day in crude oil and natural gas liquids, from 112,000 to 115,000 BOE/day including 69,500 to 71,500 bbls/day in crude oil and natural gas liquids. In addition, we are providing fourth quarter guidance of 124,500 to 128,500 BOE/day including 80,000 to 83,000 bbls/day in crude oil and natural gas liquids.

For the fourth quarter of 2021, we expect operating expenses of $8.80/BOE. We are increasing our annual operating expense guidance to $8.80/BOE from $8.25/BOE and decreasing our annual cash G&A guidance to $1.15/BOE from $1.25/BOE.

We are narrowing our full year Bakken and Marcellus differential guidance to US$2.00/bbl below WTI and US$0.55/Mcf below NYMEX from US$2.35/bbl below WTI and US$0.65/Mcf below NYMEX.

We are reducing our current tax expense guidance to US$3 million from between US$5 to US$7 million for 2021.

Our guidance numbers include the impact of the Sleeping Giant/Russian Creek Divestment, which closed on November 2, 2021. All other guidance targets remain unchanged.

Summary of 2021 Annual Expectations(1)	Target Annual Results
Capital spending	$380 million (from $360 - $400 million)
Average annual production	113,750 - 114,750 BOE/day (from 112,000 - 115,000 BOE/day)
Average annual crude oil and natural gas liquids production	69,750 - 70,750 bbls/day (from 69,500 - 71,500)
Fourth quarter average production	124,500 - 128,500 BOE/day
Fourth quarter average crude oil and natural gas liquids production	80,000 - 83,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	26%
Operating expenses	$8.80/BOE (from $8.25/BOE)
Fourth quarter operating expenses	$8.80/BOE
Transportation costs	$3.85/BOE
Cash G&A expenses	$1.15/BOE (from $1.25/BOE)
Current Income Tax expense	US$3 million (US$5 - US$7 million)

Summary of 2021 Annual Expectations(1)(2)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(2.00)/bbl (from US$(2.35)/bbl)
Average Marcellus natural gas sales price differential (compared to NYMEX natural gas)	US$(0.55)/Mcf (from US$(0.65)/Mcf)

(1) Excluding transportation costs.
(2) Based on the continued operation of DAPL.

2022 PRELIMINARY OUTLOOK

Our preliminary 2022 capital budget is approximately $500 million. As a result, we expect average annual production of approximately 122,000 BOE/day, including 75,000 bbls/day in crude oil and natural gas liquids.

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 expenses. The cash impact of hedging related to commodity derivative instruments is also analyzed as a part of this calculation.

Calculation of Netback	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Crude oil and natural gas sales	$ 664.0	$ 239.9	$ 1,533.5	$ 680.8
Less:				
Royalties	(132.8)	(48.0)	(304.9)	(138.7)
Production taxes	(38.3)	(13.6)	(86.2)	(36.7)
Operating expenses	(112.3)	(65.1)	(265.3)	(198.5)
Transportation expenses	(41.0)	(32.2)	(110.0)	(101.5)
Netback before hedging	$ 339.6	$ 81.0	$ 767.1	$ 205.4
Realized gains/(losses) on commodity derivative instruments	(62.4)	19.7	(119.0)	106.2
Netback after hedging	$ 277.2	$ 100.7	$ 648.1	$ 311.6

"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/(used in) operating activities before asset retirement obligation settlements and changes in non-cash operating working capital.

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Cash flow from/(used in) operating activities	$ 226.6	$ 137.0	$ 400.8	$ 350.3
Asset retirement obligation settlements	2.1	1.9	10.6	13.0
Changes in non-cash operating working capital	27.0	(55.8)	156.8	(97.0)
Adjusted funds flow	$ 255.7	$ 83.1	$ 568.2	$ 266.3

"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 as outlined in the Capital Investment section of this MD&A.

Calculation of Free Cash Flow	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Adjusted funds flow	$ 255.7	$ 83.1	$ 568.2	$ 266.3
Capital spending(1)	(80.2)	(35.3)	(275.7)	(239.1)
Free cash flow	$ 175.5	$ 47.8	$ 292.5	$ 27.2

(1) Capital spending excludes office expenditures, line fill and also changes in non-cash working capital. See Note 18(c) to the Interim Financial Statements for further details.

"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 non-cash derivative instrument gain/loss, asset impairment, goodwill impairment, unrealized non-cash foreign exchange gain/loss, the associated tax effect of these items, other income related to investing activities and the valuation allowance on our deferred income tax assets. See Note 18(e) to the Interim Financial Statements as it relates to other investing activities for further details.

Calculation of Adjusted Net Income	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Net income/(loss)	$ 112.0	$ (112.8)	$ 67.0	$ (719.2)
Unrealized non-cash derivative instrument (gain)/loss	16.2	19.2	226.1	(13.3)
Asset impairment	—	256.8	4.3	683.6
Unrealized non-cash foreign exchange (gain)/loss	(12.7)	0.5	(6.8)	(0.9)
Tax effect on above items	(2.4)	(72.2)	(53.4)	(175.2)
Other income related to investing activities	(5.7)	—	(5.7)	—
Goodwill impairment	—	—	—	202.8
Valuation allowance on deferred taxes	—	(73.8)	—	19.8
Adjusted net income/(loss)	$ 107.4	$ 17.7	$ 231.5	$ (2.4)

"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, accretion, 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. See the "Capital Investment" section of this MD&A.

Calculation of Adjusted Payout Ratio	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2021	2020	2021	2020
Dividends	$ 9.8	$ 6.7	$ 28.2	$ 20.0
Capital, office expenditures and line fill(1)	87.3	36.2	283.6	242.8
Sub-total	$ 97.1	$ 42.9	$ 311.8	$ 262.8
Adjusted funds flow	$ 255.7	$ 83.1	$ 568.2	$ 266.3
Adjusted payout ratio (%)	38%	52%	55%	99%

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

"Adjusted EBITDA" is used by Enerplus and its lenders to determine compliance with financial covenants under the Bank Credit Facility, term loan, and outstanding senior notes. Adjusted EBITDA is calculated on the trailing four quarters.

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	September 30, 2021
Net income/(loss)	$ (137.1)
Add:	
Interest expense	32.9
Current and deferred tax expense/(recovery)	(74.2)
DD&A and asset impairment	614.2
Other non-cash charges(2)	265.9
Sub-total	$ 701.7
Adjustment for material acquisitions and divestments(3)	68.7
Adjusted EBITDA	$ 770.4

(1) Balances above at September 30, 2021 include the nine months ended September 30, 2021 and the 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 the 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 September 30, 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 July 1, 2021 and ended September 30, 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 Dunn County Acquisition, the Bruin Acquisition and the Sleeping Giant/Russian Creek Divestment; expected impact of the Dunn County Acquisition, the Bruin Acquisition and the Sleeping Giant/Russian Creek Divestment on Enerplus' operations and financial results, including updated 2021 and future capital spending guidance and expected capital spending levels in 2022 and the future, and the impact thereof on our production levels and land holdings; expected capital budget for 2022 and allocation amongst drilling completions activity; expected production volumes in fourth quarter and in 2022, and updated 2021 and future production guidance; our intention to commence a share repurchase program, including the timing and terms thereof and quantity of purchases of common shares thereunder; expectations for funding the increase in dividends and share repurchase program from free cash flow; anticipated impact of the Dunn County Acquisition, the Bruin Acquisition and the Sleeping Giant/Russian Creek Divestment on Enerplus' future costs and expenses; expected operating strategy in 2021; the effect of Enerplus' participation in the DAPL expansion on our financial results; 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 cash flow from operating activities and adjusted funds flow; the results from our drilling program and the timing of related production and ultimate well recoveries; oil and natural gas prices and differentials and expectations regarding the market environment, our commodity risk management program in 2021 and expected hedging gains; updated 2021 Bakken and Marcellus differential guidance; expectations regarding realized oil and natural gas prices; expected operating, transportation, cash G&A costs and share-based compensation and financing expenses; updated 2021 operating expense, cash G&A cost and current tax expense guidance; 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; our future royalty and production and U.S. cash taxes; deferred income taxes, tax pools and the time at which Canadian cash taxes may be paid; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending, and working capital requirements and deficits; expectations regarding our ability to comply with or renegotiate debt covenants under the Bank Credit Facility, term loan and outstanding senior notes; expectations regarding payment of increased dividends; Enerplus' costs reduction initiatives and the expected cost savings therefrom in 2021; maintenance of current annual dividend expenditures; and the amount of future cash dividends that may be paid to 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 Dunn County Acquisition, the Bruin Acquisition and the Sleeping Giant/Russian Creek Divestment; that Enerplus will realize the expected impact of the Dunn County Acquisition, the Bruin Acquisition and the Sleeping Giant/Russian Creek Divestment on Enerplus' operations and financial results and that 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 operation of DAPL; 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 and anticipated commodity prices, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions, the impact of inflation, weather conditions, storage fundamentals and expectations regarding the duration and overall impact of COVID-19; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the ability to fund increased dividend payments and the share purchase program from free cash flow as expected and discussed in this MD&A; the 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; expected transportation expenses; the extent of our liabilities; the rates used to calculate the amount of our future abandonment and reclamation costs and asset retirement obligations; factors used to assess the realizability of our deferred income tax assets; and the availability of technology and process to achieve environmental targets. In addition, our 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 US$68.76/bbl, a NYMEX price of US$3.87/Mcf and a USD/CDN exchange rate of 1.25. In addition, the 2022 preliminary outlook is based on the following: a WTI price of US$72.88/bbl, a NYMEX price of US$4.44/Mcf and a USD/CDN exchange rate of 1.24. 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 Dunn County Acquisition, the Bruin Acquisition or the Sleeping Giant/Russian Creek Divestment; continued instability, or further deterioration, in global economic and market environment, including from COVID-19 and/or inflation; the continued high commodity price environment or further volatility or a decline in commodity prices; changes in realized prices of Enerplus' products from those currently anticipated; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; legal proceedings or other events inhibiting or preventing operation of DAPL; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; risks associated with the realization of our deferred income tax assets; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under the Bank Credit Facility, term loan, and/or outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; changes in law or government programs or policies in Canada or the United States; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in this MD&A, our Annual Information Form, our Annual MD&A and Form 40-F 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	September 30, 2021	December 31, 2020
Assets			
Current Assets			
Cash and cash equivalents		$ 54,114	$ 114,455
Accounts receivable	5	298,619	106,376
Other current assets		8,966	7,137
Derivative financial assets	17	—	3,550
		361,699	231,518
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	6	1,702,251	575,559
Other capital assets, net	6	24,944	19,524
Property, plant and equipment		1,727,195	595,083
Right-of-use assets	11	35,094	32,853
Deferred income tax asset	15	567,622	607,001
Total Assets		$ 2,691,610	$ 1,466,455
Liabilities			
Current liabilities			
Accounts payable	8	$ 415,970	$ 251,822
Dividends payable		—	2,225
Current portion of long-term debt	9	127,561	103,836
Derivative financial liabilities	17	241,658	19,261
Current portion of lease liabilities	11	13,489	13,391
		798,678	390,535
Long-term debt	9	974,280	386,586
Asset retirement obligation	10	162,099	130,208
Derivative financial liabilities	17	42,813	—
Lease liabilities	11	25,228	23,446
		1,204,420	540,240
Total Liabilities		2,003,098	930,775
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: September 30, 2021 – 255 million shares			
December 31, 2020 – 223 million shares	16	3,215,224	3,096,969
Paid-in capital		40,513	50,604
Accumulated deficit		(2,885,099)	(2,932,017)
Accumulated other comprehensive income/(loss)		317,874	320,124
		688,512	535,680
Total Liabilities & Shareholders' Equity		$ 2,691,610	$ 1,466,455
Commitments	19		
Subsequent Events	16, 20		

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 September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Revenues					
Crude oil and natural gas sales, net of royalties	12	$ 531,220	$ 191,944	$ 1,228,643	$ 542,140
Commodity derivative instruments gain/(loss)	17	(78,947)	894	(346,757)	121,340
		452,273	192,838	881,886	663,480
Expenses					
Operating		112,309	65,129	265,290	198,502
Transportation		41,008	32,209	110,019	101,544
Production taxes		38,293	13,610	86,247	36,741
General and administrative	13	15,635	8,392	44,381	41,071
Depletion, depreciation and accretion		102,380	62,147	242,748	237,224
Asset impairment	7	—	256,809	4,300	683,619
Goodwill impairment	7	—	—	—	202,767
Interest		10,451	6,339	26,801	22,301
Foreign exchange (gain)/loss	14	(12,297)	946	(5,311)	(3,198)
Transaction costs and other expense/(income)	4,10,18	(5,898)	123	(2,092)	6,195
		301,881	445,704	772,383	1,526,766
Income/(Loss) before taxes		150,392	(252,866)	109,503	(863,286)
Current income tax expense/(recovery)	15	(1,172)	(130)	3,003	(14,525)
Deferred income tax expense/(recovery)	15	39,555	(139,983)	39,458	(129,561)
Net Income/(Loss)		$ 112,009	$ (112,753)	$ 67,042	$ (719,200)
Other Comprehensive Income/(Loss)					
Unrealized gain/(loss) on foreign currency translation		21,585	(21,559)	(5,627)	52,931
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt, net of tax	17	(19,847)	9,905	3,377	(20,691)
Total Comprehensive Income/(Loss)		$ 113,747	$ (124,407)	$ 64,792	$ (686,960)
Net income/(Loss) per share					
Basic	16	$ 0.44	$ (0.51)	$ 0.27	$ (3.23)
Diluted	16	$ 0.43	$ (0.51)	$ 0.26	$ (3.23)

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 September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Share Capital				
Balance, beginning of period	$ 3,236,117	$ 3,096,969	$ 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	(20,893)	—	(20,893)	(4,731)
Share-based compensation – treasury settled	—	—	11,900	13,824
Cancellation of predecessor shares	—	—	—	(218)
Balance, end of period	$ 3,215,224	$ 3,096,969	$ 3,215,224	$ 3,096,969
Paid-in Capital				
Balance, beginning of period	$ 36,269	$ 48,758	$ 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	4,244	(3,395)	6,300	6,929
Balance, end of period	$ 40,513	$ 45,363	$ 40,513	$ 45,363
Accumulated Deficit				
Balance, beginning of period	$ (2,995,389)	$ (2,601,744)	$ (2,932,017)	$ (1,984,365)
Purchase of common shares under Normal Course Issuer Bid	8,038	—	8,038	2,195
Cancellation of predecessor shares	—	—	—	218
Net income/(loss)	112,009	(112,753)	67,042	(719,200)
Dividends declared(1)	(9,757)	(6,676)	(28,162)	(20,021)
Balance, end of period	$ (2,885,099)	$ (2,721,173)	$ (2,885,099)	$ (2,721,173)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of period	$ 316,136	$ 352,233	$ 320,124	$ 308,339
Unrealized gain/(loss) on foreign currency translation	21,585	(21,559)	(5,627)	52,931
Foreign exchange gain/(loss) on net investment hedge with U.S. denominated debt, net of tax	(19,847)	9,905	3,377	(20,691)
Balance, end of period	$ 317,874	$ 340,579	$ 317,874	$ 340,579
Total Shareholders' Equity	$ 688,512	$ 761,738	$ 688,512	$ 761,738

(1) For the three and nine months ended September 30, 2021, dividends declared were $0.038 per share and $0.112 per share, respectively (2020 – $0.03 per share and $0.09 per share, respectively).

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

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Operating Activities					
Net income/(loss)		$ 112,009	$ (112,753)	$ 67,042	$ (719,200)
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		102,380	62,147	242,748	237,224
Asset impairment	7	—	256,809	4,300	683,619
Goodwill impairment	7	—	—	—	202,767
Changes in fair value of derivative instruments	17	16,174	19,214	226,146	(13,285)
Deferred income tax expense/(recovery)	15	39,555	(139,983)	39,458	(129,561)
Foreign exchange (gain)/loss on debt and working capital	14	(12,680)	487	(6,822)	(890)
Share-based compensation and general and administrative	13,16	4,128	(2,898)	5,118	8,285
Other expense/(income)	10	(264)	—	(2,617)	—
Amortization of debt issuance costs	9	534	—	919	—
Translation of U.S. dollar cash held in Canada	14	(368)	42	(2,389)	(2,670)
Other income reclassified to Investing Activities	18	(5,720)	—	(5,720)	—
Asset retirement obligation settlements	10	(2,142)	(1,905)	(10,581)	(13,032)
Changes in non-cash operating working capital	18	(26,964)	55,827	(156,819)	97,029
Cash flow from/(used in) operating activities		226,642	136,987	400,783	350,286
Financing Activities					
Bank term loan	9	—	—	501,286	—
Bank credit facility	9	(131,706)	(1,364)	201,910	—
Repayment of senior notes	9	—	—	(99,348)	(114,010)
Proceeds from the issuance of shares	16	—	—	125,746	—
Purchase of common shares under Normal Course Issuer Bid	16	(12,855)	—	(12,855)	(2,536)
Share-based compensation – cash settled (tax withholding)	16	—	—	(4,491)	(7,232)
Dividends	16,18	(9,757)	(6,676)	(30,384)	(20,013)
Cash flow from/(used in) financing activities		(154,318)	(8,040)	681,864	(143,791)
Investing Activities					
Capital and office expenditures	18	(96,073)	(47,228)	(240,257)	(280,681)
Bruin acquisition	4	—	—	(531,134)	—
Dunn County acquisition	4	(230)	—	(374,843)	—
Property and land acquisitions		(5,557)	(2,388)	(10,583)	(8,060)
Property divestments		(271)	583	4,707	6,098
Other expense/(income)	18	5,720	—	5,720	—
Cash flow from/(used in) investing activities		(96,411)	(49,033)	(1,146,390)	(282,643)
Effect of exchange rate changes on cash & cash equivalents		2,923	(1,544)	3,402	9,046
Change in cash and cash equivalents		(21,164)	78,370	(60,341)	(67,102)
Cash and cash equivalents, beginning of period		75,278	6,177	114,455	151,649
Cash and cash equivalents, end of period		$ 54,114	$ 84,547	$ 54,114	$ 84,547

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

Notes to Condensed Consolidated Financial Statements
(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements (“interim Consolidated Financial Statements”) and notes present the financial position and results of Enerplus Corporation (the “Company” or “Enerplus”) including its Canadian and United States (“U.S.”) subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus’ 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 and nine months ended September 30, 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 obligation, income taxes, ability to realize deferred income tax assets and the fair value of derivative instruments. The estimation of crude oil and natural gas reserves and the related present value of future cash flows involves the use of independent reservoir engineering specialists and numerous inputs and assumptions including forecasted production volumes, forecasted operating, royalty and capital cost assumptions and assumptions around commodity pricing. 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.

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. As work is completed, the contractors submit invoices to the provincial government for reimbursement for the pre-approved funding amounts. Enerplus recognizes the assistance as the abandonment, remediation, and reclamation work is completed by the contractor. The benefit of the funding received by the contractor is reflected as a reduction of asset retirement obligation and recorded as other income in the Condensed Consolidated Statements of Income/(Loss).

4) ACQUISITIONS

a) Bruin E&P HoldCo, LLC Acquisition

On January 25, 2021, Enerplus Resources (USA) Corporation, an indirect wholly-owned subsidiary of Enerplus entered into a purchase agreement to acquire all of the equity interests of Bruin E&P HoldCo, LLC ("Bruin") for total cash consideration of 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 $255.4 million to crude oil and natural gas revenues, net of royalties and $60.0 million to consolidated earnings before tax from the acquisition date to September 30, 2021. Transaction costs of nil and $6.2 million were incurred for the three and nine months ended September 30, 2021, respectively.

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 for the three and nine months ended September 30, 2021 would be $531.2 million and $1,299.9 million, respectively (2020 – $288.3 million and $738.9 million, respectively). For the three and nine months ended September 30, 2021 the combined entity would have net income of $112.0 million and $20.2 million, respectively (2020 – net losses of $97.8 million and $1,431.2 million, respectively).

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 pro forma adjustments were made to reflect operating synergies that resulted from the transaction.

Purchase Price Consideration

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

($ thousands)	At March 10, 2021
Consideration	
Purchase Price (US$465 million)	$ 587,667
Purchase price adjustments	(56,533)
Total consideration	$ 531,134
Fair value of identifiable assets and liabilities of Bruin	
Other current assets	2,108
Property, plant and equipment	685,219
Right of use assets	2,391
Accounts payable	(31,920)
Asset retirement obligation	(27,759)
Derivative financial liabilities	(96,514)
Lease liabilities	(2,391)
Total identifiable net assets	$ 531,134

b) Dunn County Acquisition

On April 8, 2021, the Company announced it had entered into a purchase agreement to acquire assets in Dunn County, North Dakota from Hess Bakken Investments II, LLC 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 effective date of the acquisition was March 1, 2021 and the acquisition closed on April 30, 2021.

The acquisition was recorded as an asset acquisition as of the close date of April 30, 2021 with the results of operations reflected in these interim Consolidated Financial Statements thereafter. After purchase price adjustments, the purchase consideration including capitalized transaction costs was $376.9 million (US$306.8 million).

5) ACCOUNTS RECEIVABLE

($ thousands)		September 30, 2021		December 31, 2020
Accrued revenue	$	259,990	$	93,147
Accounts receivable – trade		43,529		16,808
Allowance for doubtful accounts		(4,900)		(3,579)
Total accounts receivable, net of allowance for doubtful accounts	$	298,619	$	106,376

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

As of September 30, 2021 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
Crude oil and natural gas properties[(1)]	$	16,572,168	$	(14,869,917)	$	1,702,251
Other capital assets		136,710		(111,766)		24,944
Total PP&E	$	16,708,878	$	(14,981,683)	$	1,727,195

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 September 30,				Nine months ended September 30,			
($ thousands)		2021		2020		2021		2020
Crude oil and natural gas properties:								
Canada cost centre	$	—	$	23,349	$	4,300	$	100,849
U.S. cost centre		—		233,460		—		582,770
Asset impairment	$	—	$	256,809	$	4,300	$	683,619

For the three and nine months ended September 30, 2021, Enerplus recorded asset impairments of nil and $4.3 million, respectively (2020 – $256.8 million and $683.6 million, respectively). During the first nine months of 2021, all asset impairments recorded related to Enerplus' Canadian cost centre, whereas the asset impairments recorded in the first nine months of 2020 related to both Canadian and U.S. cost centres. 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 September 30, 2020 through September 30, 2021:

Period	WTI Crude Oil US$/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	Exchange Rate US$/CDN$
Q3 2021	$ 57.64	$ 67.27	$ 3.00	1.27
Q2 2021	49.72	58.31	2.47	1.28
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

b) Ceiling Test Exemption

Enerplus is required to calculate a full cost ceiling test at each reporting period, using constant prices as defined by the SEC under U.S. GAAP. These prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. At March 31, 2021, the ceiling test resulted in the net carrying cost of Enerplus' crude oil and natural gas properties in its U.S. cost centre to exceed the ceiling test limitation by approximately US$265 million. This was primarily due to the difference in the ceiling value, using SEC constant prices for the Bruin assets acquired compared to the carrying value, which more closely represented fair market value based on forward prices. Enerplus requested and received a temporary exemption from the SEC to exclude the properties acquired from Bruin in the full cost ceiling test for the duration of 2021. At September 30, 2021, the ceiling test limitation exceeded the net carrying cost of the crude oil and natural gas properties, including the Bruin assets, in Enerplus' U.S. cost centre.

c) Impairment of Goodwill

At September 30, 2021, there was no goodwill remaining on the Company's Condensed Consolidated Balance Sheets (December 31, 2020 – nil). During the three and nine months ended September 30, 2020, Enerplus recorded goodwill impairment of nil and $202.8 million respectively, relating to its U.S. reporting unit. This was due to lower commodity prices in 2020, which resulted in a reduction in the fair value of the U.S. reporting unit.

8) ACCOUNTS PAYABLE

($ thousands)	September 30, 2021	December 31, 2020
Accrued payables	$ 131,826	$ 107,254
Accounts payable – trade	284,144	144,568
Total accounts payable	$ 415,970	$ 251,822

9) DEBT

($ thousands)	September 30, 2021	December 31, 2020
Current:		
Senior notes	$ 127,561	$ 103,836
Long-term:		
Bank credit facility	212,305	—
Term loan	504,317	—
Senior notes	257,658	386,586
Total debt	$ 1,101,841	$ 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 of Enerplus' 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' bank credit facility and ranks equally with the bank credit facility and outstanding senior notes. Debt issuance costs of $3.6 million have been netted against the term loan and are being amortized over the three-year term.

During 2021 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. Debt issuance costs of $2.2 million have been netted against the bank credit facility and are being amortized over the four and a half year term. 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; and
- **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.

For the three and nine months ended September 30, 2021, total amortization of debt issuance costs amounted to $0.5 million and $0.9 million, respectively.

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	$ 133,140
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	25,360
May 15, 2012	May 15 and Nov 15	3 equal annual installments beginning May 15, 2022	4.40%	US$355,000	US$178,800	226,719
					Total carrying value	$ 385,219

During the nine months ended September 30, 2021, Enerplus made its final US$22.0 million principal repayment on its 2009 senior notes and its second US$59.6 million principal repayment on its 2012 senior notes.

10) ASSET RETIREMENT OBLIGATION ("ARO")

($ thousands)	**September 30, 2021**	**December 31, 2020**
Balance, beginning of year	$ 130,208	$ 138,049
Change in estimates	5,838	1,331
Property acquisitions and development activity	804	2,246
Bruin acquisition (Note 4a)	27,759	—
Dunn County acquisition (Note 4b)	7,291	—
Divestments	(2,010)	(1,030)
Settlements	(10,581)	(17,709)
Government assistance	(2,617)	—
Accretion expense	5,407	7,321
Balance, end of period	$ 162,099	$ 130,208

Enerplus has estimated the present value of its ARO to be $162.1 million at September 30, 2021 based on a total undiscounted uninflated liability of $438.6 million (December 31, 2020 – $130.2 million and $348.4 million, respectively).

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 to ARO. For the three and nine months ended September 30, 2021, Enerplus benefited from $0.3 million and $2.6 million, respectively, in government assistance, which has been recorded as other income in the Condensed Consolidated Statements of Income/(Loss).

11) LEASES

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

($ thousands)	September 30, 2021	December 31, 2020
Assets		
Operating right-of-use assets	$ 35,094	$ 32,853
Liabilities		
Current operating lease liabilities	$ 13,489	$ 13,391
Non-current operating lease liabilities	25,228	23,446
Total lease liabilities	$ 38,717	$ 36,837
Weighted average remaining lease term (years)		
Operating leases	3.4	3.9
Weighted average discount rate		
Operating leases	3.4%	4.2%

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2021	2020	2021	2020
Operating lease cost	$ 3,565	$ 3,649	$ 10,584	$ 12,964
Variable lease cost	215	708	578	1,215
Short-term lease cost	565	1,329	2,190	8,506
Sublease income	(348)	(345)	(936)	(889)
Total	$ 3,997	$ 5,341	$ 12,416	$ 21,796

Maturities of lease liabilities, all of which are classified as operating leases at September 30, 2021 are as follows:

($ thousands)	Operating Leases
2021	$ 3,708
2022	14,134
2023	12,429
2024	7,051
2025	1,198
After 2025	2,686
Total lease payments	$ 41,206
Less imputed interest	(2,489)
Total discounted lease payments	$ 38,717
Current portion of lease liabilities	$ 13,489
Non-current portion of lease liabilities	$ 25,228

Supplemental information related to leases is as follows:

($ thousands)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Cash amounts paid to settle lease liabilities:				
Operating cash flow used for operating leases	$ 3,671	$ 3,480	$ 10,920	$ 12,322
Right-of-use assets obtained/(terminated) in exchange for lease liabilities:				
Operating leases	$ 946	$ 266	$ 11,768	$ (2,683)

12) CRUDE OIL AND NATURAL GAS SALES, NET OF ROYALTIES

($ thousands)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Crude oil and natural gas sales	$ 664,045	$ 239,920	$ 1,533,530	$ 680,777
Royalties(1)	(132,825)	(47,976)	(304,887)	(138,637)
Crude oil and natural gas sales, net of royalties	$ 531,220	$ 191,944	$ 1,228,643	$ 542,140

(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 and nine months ended September 30, 2021 and 2020 are as follows:

Three months ended September 30, 2021 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 42,584	$ 37,417	$ 3,525	$ 1,384	$ 258
United States	488,636	388,159	72,382	28,084	11
Total	$ 531,220	$ 425,576	$ 75,907	$ 29,468	$ 269

Three months ended September 30, 2020 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 27,686	$ 23,248	$ 3,349	$ 791	$ 298
United States	164,258	134,674	25,302	4,269	13
Total	$ 191,944	$ 157,922	$ 28,651	$ 5,060	$ 311

Nine months ended September 30, 2021 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 113,647	$ 99,406	$ 9,652	$ 3,867	$ 722
United States	1,114,996	878,974	177,039	58,957	26
Total	$ 1,228,643	$ 978,380	$ 186,691	$ 62,824	$ 748

Nine months ended September 30, 2020 ($ thousands)	Total revenue, net of royalties(1)	Crude oil(2)	Natural gas(2)	Natural gas liquids(2)	Other(3)
Canada	$ 67,804	$ 54,957	$ 8,858	$ 2,450	$ 1,539
United States	474,336	378,502	88,738	7,013	83
Total	$ 542,140	$ 433,459	$ 97,596	$ 9,463	$ 1,622

(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

($ thousands)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
General and administrative expense(1)	$ 10,669	$ 11,527	$ 34,424	$ 33,093
Share-based compensation expense	4,966	(3,135)	9,957	7,978
General and administrative expense	$ 15,635	$ 8,392	$ 44,381	$ 41,071

(1) Includes a non-cash lease credit of $116 and $341 for the three and nine months ended September 30, 2021 (2020 – credit of $117 and $170).

14) FOREIGN EXCHANGE

($ thousands)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Realized:				
Foreign exchange (gain)/loss	$ 751	$ 417	$ 3,900	$ 362
Translation of U.S. dollar cash held in Canada (gain)/loss	(368)	42	(2,389)	(2,670)
Unrealized:				
Translation of debt and working capital (gain)/loss	(12,680)	487	(6,822)	(890)
Foreign exchange (gain)/loss	$ (12,297)	$ 946	$ (5,311)	$ (3,198)

15) INCOME TAXES

($ thousands)	Three months ended September 30, 2021	2020	Nine months ended September 30, 2021	2020
Current tax				
Canada	$ —	$ —	$ —	$ —
United States	(1,172)	(130)	3,003	(14,525)
Current tax expense/(recovery)	(1,172)	(130)	3,003	(14,525)
Deferred tax				
Canada	$ (12,826)	$ (80,549)	$ (68,080)	$ 18,303
United States	52,381	(59,434)	107,538	(147,864)
Deferred tax expense/(recovery)	39,555	(139,983)	39,458	(129,561)
Income tax expense/(recovery)	$ 38,383	$ (140,113)	$ 42,461	$ (144,086)

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

The Company's overall net deferred income tax asset was $567.6 million as at September 30, 2021 (December 31, 2020 – $607.0 million).

16) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized unlimited number of common shares issued: (thousands)	Nine months ended September 30, 2021 Shares	Amount	Year ended December 31, 2020 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)	33,062	127,248	—	—
Purchase of common shares under Normal Course Issuer Bid	(1,658)	(20,893)	(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	255,092	$ 3,215,224	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 and nine months ended September 30, 2021 were $9.8 million and $28.2 million, respectively (2020 – $6.7 million and $20.0 million, respectively). During the third quarter of 2021, the Company's Board of Directors approved a 15% increase to the dividend to $0.038 per share, which began in September. This increase is in addition to the 10% increase approved in the second quarter of 2021. Subsequent to the quarter, the Board of Directors approved an 8% increase to the dividend to $0.041 per share beginning in December 2021.

During the nine months ended September 30, 2021, Enerplus issued 33,062,500 common shares at a price of $4.00 per common share for gross proceeds of $132.3 million (net $127.2 million, after $6.6 million in issue costs, net of $1.5 million in tax) pursuant to a bought deal prospectus offering under its base shelf prospectus.

On June 23, 2021, the Company filed a short form base shelf prospectus (the "Shelf Prospectus") with securities regulatory authorities in each of the provinces and territories of Canada and a Registration Statement with the U.S. Securities Exchange Commission. The Shelf Prospectus allows Enerplus to offer and issue up to an aggregate amount of $2.0 billion common shares, preferred shares, warrants, subscription receipts and units by way of one or more prospectus supplements during the 25-month period that the Shelf Prospectus remains valid.

On August 12, 2021 Enerplus received approval from the Toronto Stock Exchange ("TSX") to commence a Normal Course Issuer Bid ("NCIB") to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. As a result, 1,657,650 common shares were repurchased and cancelled under the NCIB at an average price of $7.75 per share, for total consideration of $12.9 million. Of the amount paid, $20.9 million was charged to share capital and $8.0 million was credited to accumulated deficit.

During the nine months ended September 30, 2020, the Company repurchased 340,434 common shares under the former NCIB at an average price of $7.44 per share, for total consideration of $2.5 million. Of the amount paid, $4.7 million was charged to share capital and $2.2 million was credited to accumulated deficit.

Subsequent to September 30, 2021 and up to and including November 3, 2021, the Company repurchased 434,700 common shares under the current NCIB at an average price of $11.52 per share, for total consideration of $5.0 million.

b) Share-based Compensation

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

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2021	2020	2021	2020
Cash:				
Long-term incentive plans (recovery)/expense	$ 1,045	$ (738)	$ 6,095	$ (2,299)
Non-Cash:				
Long-term incentive plans expense	4,244	(2,781)	5,460	8,458
Equity swap (gain)/loss	(323)	384	(1,598)	1,819
Share-based compensation expense	$ 4,966	$ (3,135)	$ 9,957	$ 7,978

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 nine months ended September 30, 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	267	2,146	2,194	4,607
Vested	(13)	(728)	(890)	(1,631)
Forfeited	—	—	(71)	(71)
Balance, end of period	809	3,970	3,058	7,837

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

Cash-settled LTI Plans

For the three and nine months ended September 30, 2021, the Company recorded a cash share-based compensation expense of $1.0 million and $6.1 million, respectively (September 30, 2020 – recovery of $0.7 million and $2.3 million, respectively).

As of September 30, 2021, a liability of $8.2 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 as Paid-in Capital on the Condensed Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At September 30, 2021 ($ thousands, except for years)	PSU[(1)]	RSU	Total
Cumulative recognized share-based compensation expense	$ 6,222	$ 11,279	$ 17,501
Unrecognized share-based compensation expense	8,356	7,455	15,811
Fair value	$ 14,578	$ 18,734	$ 33,312
Weighted-average remaining contractual term (years)	1.5	1.2	

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the three and nine months ended September 30, 2021, nil and $4.5 million (2020 – nil and $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:

	Three months ended September 30,		Nine months ended September 30,	
(thousands, except per share amounts)	2021	2020	2021	2020
Net income/(loss)	$ 112,009	$ (112,753)	$ 67,042	$ (719,200)
Weighted average shares outstanding – Basic	256,345	222,548	252,432	222,487
Dilutive impact of share-based compensation	4,486	—	4,468	—
Weighted average shares outstanding – Diluted	260,831	222,548	256,900	222,487
Net income/(loss) per share				
Basic	$ 0.44	$ (0.51)	$ 0.27	$ (3.23)
Diluted	$ 0.43	$ (0.51)	$ 0.26	$ (3.23)

17) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At September 30, 2021, the carrying value of cash and cash equivalents, accounts receivable, and accounts payable approximated their fair value due to the short-term nature of these instruments.

At September 30, 2021, the senior notes had a carrying value of $385.2 million and a fair value of $388.1 million (December 31, 2020 – $490.4 million and $494.1 million, respectively). The fair values of the bank credit facility and term loan approximate their carrying values as they bear interest at floating rates and the credit spread approximates current market rates.

The fair value of derivative contracts, senior notes, term loan, and credit facility 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 and nine months ended September 30, 2021 and 2020:

Gain/(Loss) ($ thousands)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020	Income Statement Presentation
Equity Swaps	$ 323	$ (384)	$ 1,598	$ (1,819)	G&A expense
Commodity Derivative Instruments:					
Oil	(1,772)	(18,830)	(200,319)	15,104	Commodity derivative instruments
Gas	(14,725)	—	(27,425)	—	
Total	$ (16,174)	$ (19,214)	$ (226,146)	$ 13,285	

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

($ thousands)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Unrealized change in fair value gain/(loss)	$ (16,497)	$ (18,830)	$ (227,744)	$ 15,104
Net realized gain/(loss)	(62,450)	19,724	(119,013)	106,236
Commodity derivative instruments gain/(loss)	$ (78,947)	$ 894	$ (346,757)	$ 121,340

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

	September 30, 2021		December 31, 2020		
	Liabilities		Assets	Liabilities	
($ thousands)	Current	Long-term	Current	Current	Long-term
Equity Swaps	$ 2,015	$ —	$ —	$ 3,613	$ —
Commodity Derivative Instruments:					
Oil	216,558	42,025	—	15,648	—
Gas	23,085	788	3,550	—	—
Total	$ 241,658	$ 42,813	$ 3,550	$ 19,261	$ —

On March 10, 2021, the outstanding crude oil contracts 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 contracts 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. At September 30, 2021, the fair value of the remaining Bruin contracts was a liability of $82.6 million, including $42.6 million of the original $96.5 million liability acquired. For the three and nine months ended September 30, 2021 the Company recorded a realized loss of $10.3 million and $11.9 million, respectively, on the settlement of the Bruin contracts. In addition, the Company recognized an unrealized loss of $4.6 million and $40.0 million, respectively, for the change in the fair value of the Bruin contracts over the same periods.

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 November 3, 2021:

Crude Oil Instruments:

Instrument Type[(1)(2)]	**bbls/day**	**US$/bbl**
Oct 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
Jan 1, 2022 - Jun 30, 2022		
WTI Purchased Put	12,500	75.00
WTI Sold Put	12,500	58.00
WTI Sold Call	12,500	87.63
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
Contracts acquired from Bruin[(3)]		
Oct 1, 2021 – Dec 31, 2021		
WTI Swap	7,179	43.01
Jan 1, 2022 - Sep 30, 2022		
WTI Swap	4,500	42.31
Oct 1, 2022 - Dec 31, 2022		
WTI Swap	1,834	42.65
Jan 1, 2023 - Dec 31, 2023		
WTI Swap	208	42.10
WTI Purchased Put	2,000	5.00
WTI Sold Call	2,000	75.00

(1) The total average deferred premium spent on the Company's outstanding crude oil contracts is US$0.87/bbl from October 1, 2021 - December 31, 2021 and US$1.29/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 crude oil contracts were recorded at a fair value liability of $96.5 million. At September 30, 2021, the balance was a liability of $42.6 million on the Condensed Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired contracts 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.

Natural Gas Instruments:

Instrument Type[(1)]	**MMcf/day**	**US$/Mcf**
Oct 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
Nov 1, 2021 – Mar 31, 2022		
NYMEX Purchased Put	40.0	3.43
NYMEX Sold Call	40.0	6.00
Apr 1, 2022 – Oct 31, 2022		
NYMEX Swap	40.0	3.40

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

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations and associated net investment, U.S. dollar denominated senior notes, term loan, bank credit facility, 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 September 30, 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 by the cumulative translation gain or loss on the net investment in the foreign subsidiary. At September 30, 2021, US$303.8 million of senior notes outstanding and the US$400 million term loan were designated as net investment hedges. For the three and nine months ended September 30, 2021, Other Comprehensive Income/(Loss) included an unrealized loss of $19.8 million and an unrealized gain of $3.4 million, respectively, on Enerplus' U.S. dollar denominated senior notes and term loan (2020 – $9.9 million unrealized gain and $20.7 unrealized million loss, respectively).

Interest Rate Risk:

The Company's senior notes bear interest at fixed rates while the term loan and bank credit facility bear interest at floating rates. At September 30, 2021, approximately 35% of Enerplus' debt was based on fixed interest rates and 65% on floating interest rates (December 31, 2020 – 100% fixed), with weighted average interest rates of 4.4% and 1.9%, respectively (December 31, 2020 – 4.4%). At September 30, 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 volatility in commodity prices, Enerplus is subject to an increased risk of financial loss due to non-performance or insolvency of its counterparties.

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

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 September 30, 2021, approximately 84% of Enerplus' marketing receivables were with companies considered investment grade (December 31, 2020 – 82%).

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 September 30, 2021 was $4.9 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' equity. 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 September 30, 2021, Enerplus was in full compliance with all covenants under the bank credit facility, term loan, and outstanding senior notes. If the Company breaches or anticipates breaching its covenants, the Company may be required to repay, refinance, or renegotiate the terms of the debt.

18) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Accounts receivable	$ (48,094)	$ 43,832	$ (192,847)	$ 111,091
Other assets	(8,175)	(831)	(6,435)	(1,031)
Accounts payable	29,305	12,826	42,463	(13,031)
Non-cash operating activities	$ (26,964)	$ 55,827	$ (156,819)	$ 97,029

b) Changes in Non-Cash Financing Working Capital

($ thousands)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Non-cash financing activities(1)	$ —	$ —	$ (2,225)	$ 8

(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 September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Non-cash investing activities(1)	$ (15,465)	$ (11,013)	$ 36,676	$ (37,912)

(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, excluding the Bruin and Dunn County acquisitions.

d) Cash Income taxes and Interest payments

($ thousands)	Three months ended September 30, 2021	Three months ended September 30, 2020	Nine months ended September 30, 2021	Nine months ended September 30, 2020
Cash income taxes paid/(received)	$ 954	$ (29,068)	$ 5,196	$ (59,164)
Cash interest paid	4,583	3,227	22,979	19,481

e) Other

During the three-month period ended September 30, 2021, Enerplus, received a $5.7 million distribution associated with a privately held investment. This distribution is recorded within Transaction costs and other expense/(income) on the Consolidated Statements of Income/(Loss), and reflected as an investing activity in the Condensed Consolidated Statements of Cash Flows.

19) COMMITMENTS

Effective August 1, 2021, Enerplus participated in the Dakota Access Pipeline expansion by contracting another 6,500 bbls/day of firm transportation commitments on the pipeline. The additional transportation provides access to sell a greater portion of Enerplus' production at U.S. Gulf Coast and Brent pricing.

20) SUBSEQUENT EVENT

On August 30, 2021, the Company announced it had entered into a definitive agreement to sell its interests in the Sleeping Giant field in Montana and the Russian Creek area in North Dakota in the Williston Basin, for total consideration of US$115 million, subject to customary purchase price adjustments. In addition, the Company may receive up to US$5 million in contingent payments if the WTI oil price averages over US$65 per barrel in 2022 and over US$60 per barrel in 2023. The disposition closed on November 2, 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

LEGAL COUNSEL

Blake, Cassels & Graydon LLP
Calgary, Alberta

AUDITORS

KPMG LLP
Calgary, Alberta

TRANSFER AGENT

AST Trust Company (Canada)/American Stock Transfer & Trust Company, LLC
Calgary, Alberta
Toll free: 1.800.387.0825

INDEPENDENT RESERVE ENGINEERS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS

Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

U.S. OFFICE

950 17th Street, Suite 2200
Denver, Colorado 80202

Telephone: 720.279.5500
Fax: 720.279.5550

ABBREVIATIONS

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

Enerplus
Dome Tower
Suite 3000, 333 7th Avenue SW
Calgary, Alberta
Canada T2P 2Z1
Toll Free: 1-800-319-6462
www.enerplus.com
investorrelations@enerplus.com