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NEWS RELEASE

November 4, 2021

Enerplus Announces Third Quarter 2021 Results; Updated 2021 Guidance; Preliminary 2022 Budget; Increases Share Repurchase Program and Dividend

All financial information contained within this news release has been prepared in accordance with U.S. GAAP, except as noted under "Non-GAAP Measures". This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review the "Forward-Looking Information and Statements" at the conclusion of this news release. A full copy of Enerplus' Third Quarter 2021 Financial Statements and MD&A are available on the Company's website at www.enerplus.com, under its SEDAR profile at www.sedar.com and on the EDGAR website at www.sec.gov.

Calgary, Alberta - Enerplus Corporation ("Enerplus" or the "Company") (TSX: ERF NYSE: ERF) today announced its third quarter 2021 operating and financial results, preliminary 2022 capital budget and an increase to its share repurchase program and dividend. Cash flow from operating activities for the third quarter was $226.6 million and adjusted funds flow was $255.7 million, compared to $137.0 million and $83.1 million, respectively, in the third quarter of 2020. Cash flow from operating activities and adjusted funds flow increased compared to the same period in 2020 due to higher production and commodity prices during the third quarter of 2021.

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."

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 #

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.

THIRD QUARTER PRODUCTION AND OPERATIONAL SUMMARY TABLES

Average Daily Production[1]

	Three months ended September 30, 2021					Nine months ended September 30, 2021				
	Williston Basin	Marcellus	Canadian Water-floods	Other[2]	Total	Williston Basin	Marcellus	Canadian Water-floods	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 natural 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/d)	**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.

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/(Expense)	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 news release.
(2) Ratio does not include trailing adjusted funds flow from the Brun and Dunn County acquisitions.
(3) Non-cash amounts have been excluded.
(4) Based on Company interest production volumes. See "Presentation of Production Information" below.
(5) Before transportation costs, royalties, and the effects of commodity derivative instruments.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	September 30, 2021	December 31, 2020
Assets		
Current Assets		
Cash and cash equivalents	$ 54,114	$ 114,455
Accounts receivable	298,619	106,376
Derivative financial assets	8,966	3,550
Other current assets	—	7,137
	361,699	231,518
Property, plant and equipment:		
Crude oil and natural gas properties (full cost method)	1,702,251	575,559
Other capital assets, net	24,944	19,524
Property, plant and equipment	1,727,195	595,083
Right-of-use assets	35,094	32,853
Deferred income tax asset	567,622	607,001
Total Assets	$ 2,691,610	$ 1,466,455
Liabilities		
Current liabilities		
Accounts payable	$ 415,970	$ 251,822
Dividends payable	—	2,225
Current portion of long-term debt	127,561	103,836
Derivative financial liabilities	241,658	19,261
Current portion of lease liabilities	13,489	13,391
	798,678	390,535
Long-term debt	974,280	386,586
Asset retirement obligation	162,099	130,208
Derivative financial liabilities	42,813	—
Lease liabilities	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	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

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

(CDN$ thousands, except per share amounts) 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
Revenues				
Crude oil and natural gas sales, net of royalties	$ 531,220	$ 191,944	$ 1,228,643	$ 542,140
Commodity derivative instruments gain/(loss)	(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	15,635	8,392	44,381	41,071
Depletion, depreciation and accretion	102,380	62,147	242,748	237,224
Asset impairment	—	256,809	4,300	683,619
Goodwill impairment	—	—	—	202,767
Interest	10,451	6,339	26,801	22,301
Foreign exchange (gain)/loss	(12,297)	946	(5,311)	(3,198)
Transaction costs and other expense/(income)	(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)	(1,172)	(130)	3,003	(14,525)
Deferred income tax expense/(recovery)	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	(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	$ 0.44	$ (0.51)	$ 0.27	$ (3.23)
Diluted	$ 0.43	$ (0.51)	$ 0.26	$ (3.23)

Condensed Consolidated Statements of Cash Flows

	Three months ended September 30,		Nine months ended September 30,	
(CDN$ thousands) unaudited	2021	2020	2021	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	—	256,809	4,300	683,619
Goodwill impairment	—	—	—	202,767
Changes in fair value of derivative instruments	16,174	19,214	226,146	(13,285)
Deferred income tax expense/(recovery)	39,555	(139,983)	39,458	(129,561)
Foreign exchange (gain)/loss on debt and working capital	(12,680)	487	(6,822)	(890)
Share-based compensation and general and administrative	4,128	(2,898)	5,118	8,285
Other expense/(income)	(264)	—	(2,617)	—
Amortization of debt issuance costs	534	—	919	—
Translation of U.S. dollar cash held in Canada	(368)	42	(2,389)	(2,670)
Other income reclassified to Investing Activities	(5,720)	—	(5,720)	—
Asset retirement obligation settlements	(2,142)	(1,905)	(10,581)	(13,032)
Changes in non-cash operating working capital	(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	—	—	501,286	—
Bank credit facility	(131,706)	(1,364)	201,910	—
Repayment of senior notes	—	—	(99,348)	(114,010)
Proceeds from the issuance of shares	—	—	125,746	—
Purchase of common shares under Normal Course Issuer Bid	(12,855)	—	(12,855)	(2,536)
Share-based compensation – cash settled (tax withholding)	—	—	(4,491)	(7,232)
Dividends	(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	(96,073)	(47,228)	(240,257)	(280,681)
Bruin acquisition	—	—	(531,134)	—
Dunn County acquisition	—	—	(374,613)	—
Property and land acquisitions	(5,787)	(2,388)	(10,813)	(8,060)
Property divestments	(271)	583	4,707	6,098
Other expense/(income)	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**

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.

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