Exhibit 99.1

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:

	Nine months ended September 30,						
Pricing (average for the period)	**2021**	**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.