FINANCIAL SUMMARY

2021

enerPLUS

CONTENTS

2021 FINANCIAL SUMMARY

SELECTED FINANCIAL RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2021	2020	2021	2020
Financial (US$, thousands, except ratios)				
Net Income/(Loss)	$ 176,913	$(161,566)	$ 234,441	$(693,351)
Adjusted Net Income[1]	129,958	15,272	315,669	14,522
Cash Flow from Operating Activities	283,534	70,900	604,839	335,884
Adjusted Funds Flow[1]	258,477	68,634	712,433	265,490
Dividends to Shareholders - Declared	7,884	5,207	30,535	19,962
Net Debt[1]	640,423	295,455	640,423	295,455
Capital Spending	81,059	40,193	302,348	217,246
Property and Land Acquisitions	2,744	1,584	835,147	7,492
Property Divestments	108,869	37	112,651	4,456
Net Debt to Adjusted Funds Flow Ratio[1]	0.9x	1.1x	0.9x	1.1x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ 0.71	$ (0.73)	$ 0.93	$ (3.12)
Net Income/(Loss) - Diluted	0.68	(0.73)	0.90	(3.12)
Weighted Average Number of Shares Outstanding (000's) - Basic	250,359	222,548	251,909	222,503
Weighted Average Number of Shares Outstanding (000's) - Diluted	258,365	222,548	259,851	222,503
Selected Financial Results per BOE[2][3]				
Crude Oil & Natural Gas Sales[4]	$ 52.82	$ 23.45	$ 44.04	$ 20.72
Commodity Derivative Instruments	(7.12)	2.67	(4.84)	3.47
Operating Expenses	(8.46)	(7.82)	(8.69)	(7.38)
Transportation Costs	(4.27)	(3.70)	(3.81)	(3.69)
Production Taxes	(3.47)	(1.58)	(3.03)	(1.40)
General and Administrative Expenses	(1.12)	(1.40)	(1.14)	(1.26)
Cash Share-Based Compensation	(0.22)	(0.11)	(0.20)	0.04
Interest, Foreign Exchange and Other Expenses	(0.82)	(0.80)	(1.08)	(1.01)
Current Income Tax Recovery/(Expense)	(0.02)	—	(0.08)	0.40
Adjusted Funds Flow[1]	$ 27.32	$ 10.71	$ 21.17	$ 9.89

SELECTED OPERATING RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2021	2020	2021	2020
Average Daily Production[3]				
Crude Oil (bbls/day)	55,419	35,118	48,514	36,681
Natural Gas Liquids (bbls/day)	9,540	4,615	7,823	4,499
Natural Gas (Mcf/day)	227,186	179,265	215,304	191,014
Total (BOE/day)	102,823	69,611	92,221	73,016
% Crude Oil and Natural Gas Liquids	63%	57%	61%	56%
Average Selling Price[3][4]				
Crude Oil (per bbl)	$ 75.54	$ 36.89	$ 66.05	$ 33.30
Natural Gas Liquids (per bbl)	38.90	13.21	29.86	7.79
Natural Gas (per Mcf)	4.02	1.57	2.98	1.40
Net Wells Drilled	10	2	25	42

(1) This financial measure is a non-GAAP financial measure and may not be directly comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section in this MD&A.
(2) Non-cash amounts have been excluded.
(3) Based on Net production volumes. See "Basis of Presentation" section in the following MD&A.
(4) Before transportation costs and commodity derivative instruments.

Average Benchmark Pricing	Three months ended December 31, 2021	2020	Twelve months ended December 31, 2021	2020
WTI crude oil ($/bbl)	$ 77.19	$ 42.66	$ 67.92	$ 39.40
Brent (ICE) crude oil ($/bbl)	79.80	45.24	70.79	43.21
NYMEX natural gas – last day ($/Mcf)	5.83	2.66	3.84	2.08
CDN/US average exchange rate	0.79	0.77	0.80	0.75

Share Trading Summary For the twelve months ended December 31, 2021	U.S.[1] – ERF (US$)	CDN[2] – ERF (CDN$)
High	$ 11.18	$ 13.76
Low	$ 3.07	$ 3.94
Close	$ 10.58	$ 13.34

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

2021 Dividends per Share	US$[1]	CDN$
First Quarter Total	$ 0.024	$ 0.030
Second Quarter Total	$ 0.035	$ 0.043
Third Quarter Total	$ 0.030	$ 0.038
Fourth Quarter Total	$ 0.032	$ 0.041
Total Year to Date	$ 0.121	$ 0.152

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

2021 HIGHLIGHTS

FINANCIAL & OPERATIONAL HIGHLIGHTS

- We delivered 2021 total production of 92,221 BOE/day, which was at the high end of our guidance range (91,450 to 92,250 BOE/day). Total production in 2021 was 26% higher compared to 2020. Crude oil and natural gas liquids production in 2021 was 56,337 bbls/day, which was in line with our guidance (55,950 to 56,750 bbls/day) and 37% higher compared to 2020. The higher year-over-year production was primarily due to the acquisitions in North Dakota completed during the first half of 2021 and our development program in 2021.

- Full year 2021 net income was $234.4 million, or $0.93 per share, compared to a net loss of $693.4 million, or ($3.12) per share, in 2020. Excluding certain non-cash or non-recurring items, 2021 adjusted net income[1] was $315.7 million, or $1.25 per share, compared to $14.5 million, or $0.07 per share, in 2020. The higher net income and adjusted net income[1] was primarily due to higher production and commodity prices. The net loss in 2020 was primarily due to non-cash impairments of $900.9 million as a result of low commodity prices in 2020.

- Our 2021 Bakken crude oil price differential was $2.15/bbl below WTI, compared to $5.39/bbl below WTI in 2020. Bakken pricing strengthened throughout the year as basin-wide production fell below 2020 levels, while pipeline egress capacity out of the basin increased with the Dakota Access Pipeline ("DAPL") expansion start-up in August. Our 2021 Marcellus natural gas price differential was $0.81/Mcf below NYMEX, compared to $0.65/Mcf below NYMEX in 2020. The weaker pricing was driven by warmer than anticipated weather for much of the year and volatility in NYMEX benchmark prices.

- Operating expenses in 2021 were $8.69/BOE, compared to $7.38/BOE in 2020. Cash general and administrative ("G&A") expenses in 2021 were $1.14/BOE, compared to $1.26/BOE in 2020.

- Capital spending totaled $302.3 million in 2021, in line with our guidance of $303 million.

- During 2021, a total of $153.7 million was returned to shareholders through share repurchases and dividends. We paid $30.5 million in dividends in 2021 and repurchased 12.9 million shares at an average price of $9.55 (CDN$12.06) per share for a total cost of $123.2 million.

- We ended the year with net debt[1] of $640.4 million, and we were undrawn on our $900 million sustainability-linked bank credit facility ("Bank Credit Facility"). At December 31, 2021, our net debt to adjusted funds flow ratio[1] was 0.9x.

RESERVES HIGHLIGHTS

U.S. Standards[2] - after deduction of royalties ("net"), constant prices, U.S. dollars:

- Year end 2021 reserves summary:
  - Net proved developed producing reserves were 200 MMBOE, an increase of 77% year-over-year
  - Net total proved reserves were 339 MMBOE, an increase of 163% year-over-year
- Enerplus added 244 MMBOE of net proved reserves in 2021 (including acquisitions, divestments, technical revisions and economic factors), replacing its 2021 production by over seven times
- Net proved finding, development and acquisition ("FD&A") costs were $9.33/BOE, including future development costs ("FDC")

Canadian NI 51-101 Standards[3] - before deduction of royalties ("gross"), forecast prices, U.S. dollars:

- Year end 2021 reserves summary:
  - Gross proved developed producing reserves were 243 MMBOE, an increase of 37% year-over-year
  - Gross total proved reserves were 415 MMBOE, an increase of 37% year-over-year
  - Gross proved plus probable ("2P") reserves were 616 MMBOE, an increase of 45% year-over-year
- Enerplus added 233 MMBOE of gross 2P reserves in 2021 (including acquisitions, divestments, technical revisions and economic factors), replacing its 2021 production by over five times
- Gross proved FD&A costs were $9.75/BOE and gross 2P FD&A costs were $8.71/BOE, including FDC

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[1] This financial measure is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" section in this MD&A.
[2] See "Presentation of Reserves Information" section in this MD&A for definition of U.S. Standards.
[3] See "Basis of Presentation" section in this MD&A for definition of Canadian NI 51-101 Standards.

Management's Discussion and Analysis ("MD&A")

The following discussion and analysis of financial results is dated February 24, 2022 and is to be read in conjunction with the audited consolidated financial statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2021 and 2020 and for the years ended December 31, 2021, 2020 and 2019.

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 and Other Financial Measures" at the end of this MD&A for further information.

BASIS OF PRESENTATION

The Financial Statements have been prepared by management in accordance with U.S. GAAP. As previously announced, the Company has elected to change its reporting currency from Canadian dollars to U.S. dollars since the majority of the Company's crude oil and natural gas properties are located in the U.S., and to facilitate a more direct comparison to other U.S. upstream exploration and development companies. The change in reporting currency is a voluntary change, accounted for retrospectively, whereby all prior periods have been restated to U.S. dollars. See Note 2 to the Financial Statements for further details. All references to $ or US$ are to U.S. dollars and references to CDN$ are to Canadian dollars. All financial information presented in U.S. dollars and Canadian dollars has been rounded to the nearest million unless otherwise indicated.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE 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 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1 or 0.167:1, as applicable, utilizing a conversion on this basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading.

In accordance with U.S. GAAP, crude oil and natural gas sales are presented net of royalties in the Financial Statements. In addition, unless otherwise noted, all production volumes are presented on a "net" basis (after deduction of royalty obligations plus the Company's royalty interests) consistent with U.S. oil and gas reporting standards. Previously, Enerplus disclosed its production volumes on a "company interest" basis (before deduction of royalty obligation plus the Company's royalty interests). All reserves information in this MD&A has been prepared in accordance with Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("Canadian NI 51-101 Standards") effective December 31, 2021. Reserves information in this MD&A is presented in accordance with Canadian NI 51-101 Standards and also in accordance with oil and gas disclosure framework of the United States Securities and Exchange Commission (the "SEC"). See "Presentation of Reserves Information" section in this MD&A.

All references to "liquids" in this MD&A include light and medium 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.

For more details on our acquisition of Bruin E&P HoldCo, LLC ("Bruin"), see Note 3 to the Financial Statements (the "Bruin Acquisition") 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 of certain assets in the Williston Basin ("Dunn County") from Hess Bakken Investments II, LLC ("Hess"), see Note 3 to the Financial Statements (the "Dunn County Acquisition") 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.

The following table provides our net production volumes, disclosed throughout our MD&A, reconciled to company interest production volumes.

Average Daily Production Volumes	Year ended December 31, 2021	2020	2019
Net production volumes			
Light and medium oil (bbls/day)	2,231	2,601	2,964
Heavy oil (bbls/day)	3,302	3,424	3,748
Tight oil (bbls/day)	42,981	30,656	32,958
Total crude oil (bbls/day)	48,514	36,681	39,670
Natural gas liquids (bbls/day)	7,823	4,499	3,952
Conventional natural gas (Mcf/day)	7,818	11,416	21,320
Shale gas (Mcf/day)	207,486	179,598	204,261
Total natural gas (Mcf/day)	215,304	191,014	225,581
Net production volumes (BOE/day)	92,221	73,016	81,219
Royalty volumes including royalty interest volumes			
Light and medium oil (bbls/day)	813	676	944
Heavy oil (bbls/day)	794	477	969
Tight oil (bbls/day)	10,309	7,587	8,121
Total crude oil (bbls/day)	11,916	8,740	10,034
Natural gas liquids (bbls/day)	1,929	1,134	977
Conventional natural gas (Mcf/day)	708	898	2,080
Shale gas (Mcf/day)	51,385	45,945	50,790
Total natural gas (Mcf/day)	52,093	46,843	52,870
Royalty volumes (BOE/day)	22,527	17,681	19,823
Company interest production volumes			
Light and medium oil (bbls/day)	3,044	3,277	3,908
Heavy oil (bbls/day)	4,096	3,901	4,717
Tight oil (bbls/day)	53,290	38,243	41,079
Total crude oil (bbls/day)	60,430	45,421	49,704
Natural gas liquids (bbls/day)	9,752	5,633	4,929
Conventional natural gas (Mcf/day)	8,526	12,314	23,400
Shale gas (Mcf/day)	258,871	225,543	255,051
Total natural gas (Mcf/day)	267,397	237,857	278,451
Company interest production volumes (BOE/day)	114,748	90,697	101,042

2021 FOURTH QUARTER OVERVIEW

Fourth quarter production averaged 102,823 BOE/day, at the high end of our fourth quarter production guidance range of 100,000 – 103,200 BOE/day and an increase compared to production of 99,280 BOE/day in the third quarter of 2021. Crude oil and natural gas liquids production averaged 64,959 bbls/day compared to the third quarter average of 63,071 bbls/day, in line with our fourth quarter liquids production guidance range of 64,150 – 66,550 bbls/day. Our fourth quarter capital spending was $81.1 million, bringing total 2021 capital spending to $302.3 million, in line with our revised guidance of $303 million.

On November 2, 2021, we completed the divestment of 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 $115.0 million, subject to customary purchase price adjustments. In addition, we may receive up to $5.0 million in contingent consideration if the WTI oil price averages over $65/bbl in 2022 and $60/bbl in 2023. The production associated with the working interest in these properties was approximately 2,400 BOE/day.

We reported net income of $176.9 million in the fourth quarter compared to net income of $98.1 million in the third quarter of 2021. The increase in net income was primarily the result of a $78.5 million increase in crude oil and natural gas sales as a result of higher production, higher realized prices and a decrease in commodity derivative instrument losses. These amounts were offset by an increase in deferred income tax expense compared to the third quarter of 2021.

Fourth quarter cash flow from operating activities and adjusted funds flow[1] increased to $283.5 million and $258.5 million respectively, from $182.2 million and $203.1 million respectively, in the third quarter of 2021 primarily due to an increase in crude oil and natural gas sales as a result of higher production and realized prices.

Selected Fourth Quarter U.S and Canadian Financial Results

	Three months ended December 31, 2021			Three months ended December 31, 2020		
($ millions, except per unit amounts)	U.S.	Canada	Total	U.S.	Canada	Total
Average Daily Production Volumes						
Light and medium oil (bbls/day)	—	2,185	2,185	—	2,460	2,460
Heavy oil (bbls/day)	—	3,224	3,224	—	3,766	3,766
Tight oil (bbls/day)	50,010	—	50,010	28,892	—	28,892
Total crude oil (bbls/day)	50,010	5,409	55,419	28,892	6,226	35,118
Natural gas liquids (bbls/day)	9,236	304	9,540	4,172	443	4,615
Conventional natural gas (Mcf/day)	—	7,997	7,997	—	9,581	9,581
Shale gas (Mcf/day)	218,952	237	219,189	169,541	143	169,684
Total natural gas (Mcf/day)	218,952	8,234	227,186	169,541	9,724	179,265
Total average daily production (BOE/day)	95,738	7,085	102,823	61,321	8,290	69,611
Pricing(1)						
Crude oil (per bbl)	$ 76.85	$ 64.12	$ 75.54	$ 37.79	$ 32.49	$ 36.89
Natural gas liquids (per bbl)	38.57	47.52	38.90	12.38	20.72	13.21
Natural gas (per Mcf)	4.01	4.12	4.02	1.52	2.53	1.57
Property, Plant and Equipment						
Capital and office expenditures	$ 77.6	$ 4.0	$ 81.6	$ 38.3	$ 2.4	$ 40.7
Acquisitions, including property and land	2.1	0.6	2.7	1.2	0.4	1.6
Property divestments	(108.0)	(0.9)	(108.9)	—	—	—
Netback Before Impact of Commodity Derivative Contracts(2)						
Crude oil and natural gas sales	$ 463.2	$ 36.4	$ 499.6	$ 127.8	$ 22.3	$ 150.1
Operating expenses	(69.2)	(10.8)	(80.0)	(39.2)	(10.9)	(50.1)
Transportation costs	(39.1)	(1.3)	(40.4)	(21.9)	(1.8)	(23.7)
Production taxes	(32.3)	(0.5)	(32.8)	(9.8)	(0.3)	(10.1)
Netback before impact of commodity derivative contracts	$ 322.6	$ 23.8	$ 346.4	$ 56.9	$ 9.3	$ 66.2
Other Expenses						
Asset impairment	$ —	$ —	$ —	$ 218.2	$ 26.3	$ 244.5
Commodity derivative instruments loss/(gain)	—	(1.1)	(1.1)	—	11.3	11.3
General and administrative expense(3)	11.6	9.8	21.4	10.1	2.7	12.8
Current income tax expense/(recovery)	0.2	—	0.2	—	—	—

(1) Before transportation costs and the effects of commodity derivative instruments.
(2) This financial measure is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" section in this MD&A.
(3) Includes share-based compensation.

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

Comparing the fourth quarter of 2021 with the same period in 2020:

- Average daily production was 102,823 BOE/day, an increase of 48% from 69,611 BOE/day in the fourth quarter of 2020. The increase in crude oil and natural gas production was primarily due to the additional production resulting from the Bruin and Dunn County acquisitions completed during the first half of 2021. Production for the three months ended December 31, 2020 was impacted by the suspension of our operated North Dakota drilling and completions program early in 2020 due to weak commodity prices.

- Our crude oil and natural gas liquids production accounted for 63% of our total production mix in the fourth quarter of 2021, compared to 57% in 2020.

- Capital spending increased to $81.1 million compared to $40.2 million in the fourth quarter of 2020 due to the suspension of operated drilling and completions activity in North Dakota during the second quarter of 2020. The majority of our capital spending in the fourth quarter of 2021 was focused on our U.S. crude oil properties, including the drilling of ten gross wells and the completion of eight gross and three net non-operated wells.

- Operating expenses were $80.0 million or $8.46/BOE compared to $50.1 million or $7.82/BOE in the fourth quarter of 2020. Operating expenses increased on a per BOE basis due to higher U.S. crude oil production, as a result of the Bruin and Dunn County acquisitions, and increased liquids weighting. In addition, operating expenses increased due to higher well service activity in the fourth quarter of 2021 and higher water handling charges as a result of contracts with price escalators linked to WTI crude oil prices which were triggered in 2021.

- Cash G&A expenses increased to $10.6 million compared to $8.9 million in 2020, and decreased on a per BOE basis to $1.12/BOE in the fourth quarter of 2021, compared to $1.40/BOE in the same period of 2020 due to increased production.

- During the fourth quarter of 2021, our Bakken crude oil price differential narrowed to $0.88/bbl below WTI, compared to $5.12/bbl below WTI for the same period in 2020. Bakken differentials strengthened throughout the year due to an improved supply and demand balance and excess pipeline capacity in the region. Our fourth quarter 2021 Marcellus natural gas differential was $1.70/Mcf below NYMEX, compared to $1.07/Mcf below NYMEX during the same period in 2020. Our Marcellus differential widened due to volatility in NYMEX pricing and weaker local markets during the fourth quarter of 2021.

- We reported net earnings of $176.9 million in the fourth quarter of 2021 compared to a net loss of $161.6 million in the fourth quarter of 2020. Our net earnings increased by $338.5 million due to an increase in production as a result of the Bruin and Dunn County acquisitions during 2021 and stronger commodity prices. The net loss in the fourth quarter of 2020 was primarily due to a non-cash property, plant and equipment ("PP&E") impairment of $244.5 million.

- Cash flow from operating activities and adjusted funds flow[1] increased to $283.5 million and $258.5 million, respectively, compared to $70.9 million and $68.6 million in the fourth quarter of 2020. The increases were primarily the result of a $349.5 million increase in crude oil and natural gas sales due to increased production and higher commodity prices.

- During the fourth quarter, the Board of Directors approved an 8% increase to the dividend to CDN $0.041 ($0.03) per common share, to be paid quarterly, beginning December 2021 (2020 – CDN$0.03 ($0.02)). In addition, during the fourth quarter of 2021, we repurchased and cancelled 11,240,071 common shares under the Normal Course Issuer Bid ("NCIB") at an average price of $10.08 (CDN$12.70) per common share. No common shares were repurchased during the fourth quarter of 2020.

- Net debt to adjusted funds flow ratio[1] was 0.9x in the fourth quarter of 2021, excluding the trailing adjusted funds flow associated with the Bruin and Dunn County acquisitions prior to close, compared to 1.1x in the fourth quarter of 2020.

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

2021 OVERVIEW AND 2022 OUTLOOK

U.S. Dollars and Average Daily Production

The following table outlines Enerplus' updated 2021 guidance, 2021 actual results and 2022 guidance presented in U.S. dollars and net production volumes. Our 2022 guidance below has not been adjusted to reflect the potential divestment of our Canadian assets as announced on February 2, 2022.

Summary of Guidance and Results	Revised 2021 Guidance	2021 Results	2022 Guidance
Capital spending ($ millions)	$303	$302	$370 - $430
Average annual production (BOE/day)	91,450 - 92,250	92,221	95,500 - 100,500
Average annual crude oil and natural gas liquids production (bbls/day)	55,950 - 56,750	56,337	58,000 - 62,000
Fourth quarter average production (BOE/day)	100,000 - 103,200	102,823	—
Fourth quarter average crude oil and natural gas liquids production (bbls/day)	64,150 - 66,550	64,959	—
Average production tax rate (% of net sales, before transportation)	7%	7%	7%
Operating expenses (per BOE)	$8.73	$8.69	$9.50 - $10.50
Transportation costs (per BOE)	$3.82	$3.81	$4.15
Cash G&A expenses (per BOE)	$1.14	$1.14	$1.25
Current tax expense ($ millions)	$3	$3	$10

Differential/Basis Outlook and Results(2)			
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	$(2.18)/bbl	$(2.15)/bbl	$(0.50)/bbl
Average Marcellus natural gas differential (compared to NYMEX natural gas)	$(0.55)/Mcf	$(0.81)/Mcf	$(0.75)/Mcf

(1) This financial measure, including related guidance is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" section in this MD&A.
(2) Excludes transportation costs.

2021 OVERVIEW

During 2021, global economies began to recover from the coronavirus ("COVID-19") pandemic and demand for crude oil improved significantly throughout the year. This resulted in higher crude oil prices and improved market sentiment compared to 2020. We are committed to returning capital to shareholders and delivering strong operational performance, while maintaining low financial leverage. In 2021, as commodity prices improved, a total of $153.7 million was returned to shareholders through share repurchases and dividends, compared to $21.9 million in 2020.

During the first half of 2021, we completed two acquisitions in North Dakota, which we expect to provide meaningful free cash flow[1] and high-return drilling inventory, while increasing the scope and scale of our business. As a result of the Bruin and Dunn County acquisitions and the success of our 2021 capital program, we delivered crude oil and natural gas liquids production growth of 37% and overall production growth of 26% compared to 2020.

On March 10, 2021, we completed the acquisition of Bruin, which held oil and gas interests in properties located in the Williston Basin in North Dakota. The total cash consideration was $465.0 million or $420.2 million after purchase price adjustments. We also completed the acquisition of certain assets in the Williston Basin in the Dunn County area from Hess on April 30, for total cash consideration of $312.0 million, before purchase price adjustments. The final purchase consideration including capitalized transaction costs, was $306.8 million.

On November 2, 2021, Enerplus completed the divestment of interests in the Sleeping Giant field in Montana and the Russian Creek area in North Dakota in the Williston Basin for total cash consideration of $115.0 million, before purchase price adjustments. After purchase price adjustments and transaction costs, adjusted proceeds were $107.8 million. In addition, Enerplus may receive up to $5.0 million in contingent consideration if the WTI oil price averages over $65/bbl in 2022 and $60/bbl in 2023.

Our 2021 annual average production was 92,221 BOE/day with crude oil and natural gas liquids volumes of 56,337 bbls/day, meeting our revised production guidance target of 91,450 – 92,250 BOE/day and revised crude oil and natural gas liquids production guidance of 55,950 – 56,750 bbls/day. Our capital spending[1] for the year totaled $302.3 million, in line with our revised guidance of $303.0 million. The majority of our capital was directed to our U.S. crude oil properties, with approximately 85% of total spending focused on our North Dakota properties.

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

Our Bakken sales price differentials averaged $2.15/bbl below WTI, in line with our revised guidance of $2.18/bbl below WTI. Bakken differentials strengthened throughout the year due to an improved supply and demand balance and excess pipeline capacity in the region. Our Marcellus differential of $0.81/Mcf below NYMEX was wider than our revised differential guidance of $0.55/Mcf below NYMEX due to volatility in NYMEX pricing and weaker local markets as a result of record high temperatures in the Northeast U.S. during the fourth quarter of 2021.

Operating expenses were $8.69/BOE, in line with our revised guidance of $8.73/BOE and representing an 18% increase from the prior year. The increase was primarily due to an increased liquids weighting as a result of the Bruin and Dunn County acquisitions. In addition, operating expenses increased due to higher well service activity and higher water handling charges. Cash G&A expenses were $1.14/BOE, in line with our revised guidance of $1.14/BOE.

Cash flow from operations and adjusted funds flow[1] increased to $604.8 million and $712.4 million, respectively, from $335.8 million and $265.5 million in 2020. The increase was mainly due to an increase in crude oil and natural gas sales as a result of an increase in realized commodity prices and higher production compared to 2020. This was partially offset by an increase in realized commodity derivative instrument losses.

We reported net income of $234.4 million in 2021, compared to a net loss of $693.4 million in 2020. The increase in net income was primarily due to an increase in crude oil and natural gas sales as a result of increased production and improved commodity prices. These increases were partially offset by an increase in commodity derivative instrument losses and income tax expense in 2021 compared to a recovery in 2020. Net income in 2020 was also impacted by non-cash impairments of $900.9 million as a result of low commodity prices during the period.

During 2021, a total of $153.7 million was returned to shareholders through share repurchases and dividends. Since renewing the NCIB in the third quarter of 2021, we repurchased 5% of our outstanding common shares at an average price of $9.55 (CDN$12.06) per share. During 2021, we increased our quarterly dividend three times resulting in a 37% increase to CDN$0.041 ($0.03) per common share totaling $30.5 million (December 31, 2020 $20.0 million).

Net debt[1] at December 31, 2021 was $640.4 million, comprised of senior notes and a term loan totaling $701.8 million, less $61.4 million of cash on hand. Our net debt to adjusted funds flow ratio[1] decreased to 0.9x, excluding the trailing adjusted funds flow[1] associated with the Bruin and Dunn County acquisitions prior to close. At December 31, 2021, we were undrawn on our $900 million Bank Credit Facility.

2022 OUTLOOK

In 2022, we plan to continue to focus on creating value for shareholders through sustainable crude oil and natural gas liquids production growth. The 2022 capital budget is expected to deliver robust free cash flow[1]. We expect our capital spending for 2022 to range between $370 million – $430 million, with the majority directed to our North Dakota assets.

Annual average production is expected to be 95,500 – 100,500 BOE/day, including 58,000 – 62,000 bbl/day of crude oil and natural gas liquids production.

We expect our Bakken sales price differential to average $0.50/bbl below WTI in 2022. In the Marcellus, we have a differential outlook of $0.75/Mcf below NYMEX in 2022.

We expect operating expenses to average between $9.50 – $10.50/BOE and cash G&A expenses to average $1.25/BOE during 2021. We also expect current income tax expense of approximately $10 million for 2022.

To support our 2022 capital program, we have commodity derivative contracts in place for approximately 23,200 bbls/day of our expected crude oil production for 2022 and 10,000 bbls/day for January 1 to June 30, 2023. For natural gas, we have contracts in place for 40,000 Mcf/day for January 1 to February 28, 2022 and 100,000 Mcf/day for March 1 to October 31, 2022.

We plan to continue to return capital to our shareholders, including the repurchase of the remaining authorization under the NCIB by the end of July 2022, based on current market conditions. We intend to renew the NCIB in August 2022. Subsequent to December 31, 2021, the Board of Directors also approved a first quarter dividend payment of $0.033 per share to be paid in March 2022.

On February 2, 2022, we announced our plans to initiate a divestment process for our Canadian assets. Production from our Canadian assets averaged approximately 7,200 BOE/day in 2021. Our 2022 guidance has not been adjusted to reflect the potential divestment of our Canadian assets.

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

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2021	2020	2019
Light and medium oil (bbls/day)	2,231	2,601	2,964
Heavy oil (bbls/day)	3,302	3,424	3,748
Tight oil (bbls/day)	42,981	30,656	32,958
Total crude oil (bbls/day)	48,514	36,681	39,670
Natural gas liquids (bbls/day)	7,823	4,499	3,952
Conventional natural gas (Mcf/day)	7,818	11,416	21,320
Shale gas (Mcf/day)	207,486	179,598	204,261
Total natural gas (Mcf/day)	215,304	191,014	225,581
Total daily sales (BOE/day)	92,221	73,016	81,219

Production in 2021 averaged 92,221 BOE/day, in line with our revised production guidance range of 91,450 – 92,250 BOE/day, and resulted in a 26% increase compared to 2020 production of 73,016 BOE/day. Crude oil and natural gas liquids production in 2021 averaged 56,337 bbls/day, in line with our revised guidance range of 55,950 – 56,750 bbls/day. Compared to 2020, our crude oil and natural gas liquids production increased 37% due to production from the Bruin and Dunn County assets acquired in the first half of 2021 and the impact of 43 net wells coming onstream in North Dakota during 2021. Production in 2020 was impacted by the temporary curtailment of certain crude oil and natural gas liquids properties and the suspension of all operated drilling and completion activity in North Dakota during the second quarter of 2020, in response to the significant decline in crude oil prices.

Our U.S. production volumes increased by 32% compared to 2020 and our U.S. crude oil and natural gas liquids production increased by 46% to 50,481 bbls/day, primarily due to production from the Bruin and Dunn County assets in 2021, compared to 2020, which had temporary production curtailments and the suspension of our operated North Dakota drilling and completions program early in 2020 due to weak commodity prices. Natural gas production in the Marcellus was consistent in comparison to 2020 with 25,565 BOE/day in 2021.

Canadian production volumes decreased by 15% compared to the prior year, due to higher royalty rates in 2021 as a result of higher commodity prices along with a minor divestment of certain properties in Alberta in 2021.

Our crude oil and natural gas liquids production accounted for 61% of our total average daily production in 2021, an increase from 56% in 2020.

Production for 2020 decreased by 8,203 BOE/day to 73,016 BOE/day, compared to 2019. The 10% decrease was largely due to the temporary curtailments and the suspension of all operated drilling and completion activity in North Dakota during the second quarter of 2020.

2022 Guidance

We expect annual average production for 2022 of 95,500 – 100,500 BOE/day, including 58,000 – 62,000 bbls/day of crude oil and natural gas liquids production.

Pricing

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

Pricing (average for the period)	2021	2020	2019
Benchmarks			
WTI crude oil ($/bbl)	$ 67.92	$ 39.40	$ 57.03
Brent (ICE) crude oil ($/bbl)	70.79	43.21	64.18
NYMEX natural gas – last day ($/Mcf)	3.84	2.08	2.63
CDN/US average exchange rate	0.80	0.75	0.75
CDN/US period end exchange rate	0.79	0.79	0.77
Enerplus selling price(1)			
Crude oil ($/bbl)	$ 66.05	$ 33.30	$ 52.00
Natural gas liquids ($/bbl)	29.86	7.79	11.45
Natural gas ($/Mcf)	2.98	1.40	2.16
Average benchmark differentials			
Bakken DAPL - WTI ($/bbl)	$ (0.79)	$ (4.27)	$ (3.46)
Brent (ICE) - WTI ($/bbl)	2.87	3.81	7.15
MSW Edmonton – WTI ($/bbl)	(3.88)	(5.33)	(4.88)
WCS Hardisty – WTI ($/bbl)	(13.04)	(12.60)	(12.76)
Transco Leidy monthly – NYMEX ($/Mcf)	(0.94)	(0.72)	(0.46)
Transco Z6 Non-New York monthly – NYMEX ($/Mcf)	(0.36)	(0.34)	0.23
Enerplus realized differentials(1)(2)			
Bakken crude oil – WTI ($/bbl)	$ (2.15)	$ (5.39)	$ (3.98)
Marcellus natural gas – NYMEX ($/Mcf)	(0.81)	(0.65)	(0.39)
Canada crude oil – WTI ($/bbl)	(12.94)	(13.22)	(12.31)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Benchmark WTI prices averaged $67.92/bbl in 2021, a 72% increase from 2020 due to improved crude oil demand as economies recovered from the impacts of the COVID-19 pandemic and the impact of lower capital spending by North American producers throughout 2020 and 2021. Globally, the market balance remains in a supply and demand deficit, supported by the Organization of the Petroleum Exporting Countries Plus ("OPEC+") gradually returning curtailed supply to the market.

Our 2021 realized crude oil price averaged $66.05/bbl, representing a 98% increase compared to 2020, reflecting the improvement in WTI pricing as well as stronger realized differentials for both U.S. and Canadian crude oil production.

Our Bakken sales price differentials improved by $3.24/bbl in 2021 compared to 2020, averaging $2.15/bbl below WTI. Bakken pricing strengthened throughout the year as basin-wide production fell below 2020 levels while pipeline egress capacity out of the basin increased with the DAPL expansion start-up in August 2021. Given the increased pipeline egress, we expect our realized Bakken differential to continue to narrow in 2022 and average $0.50/bbl below WTI. As realized pricing is reported net of royalties, our reported Bakken sales price differential is wider than it would have been if reported on a company interest basis.

Canadian crude oil differentials improved modestly in 2021 compared to the prior year. Differentials were relatively consistent throughout the year with minor improvements for both light and heavy grade crude oil during the fourth quarter of 2021 with the completion and start-up of Enbridge's Line 3 expansion project.

We realized an average price of $29.86/bbl on our natural gas liquids production in 2021, a 283% increase compared to 2020. North American heating demand spiked during the first quarter of 2021 and export demand remained strong through the year. With stable production levels and increasing WTI prices, inventories declined resulting in higher North American natural gas liquids prices in 2021.

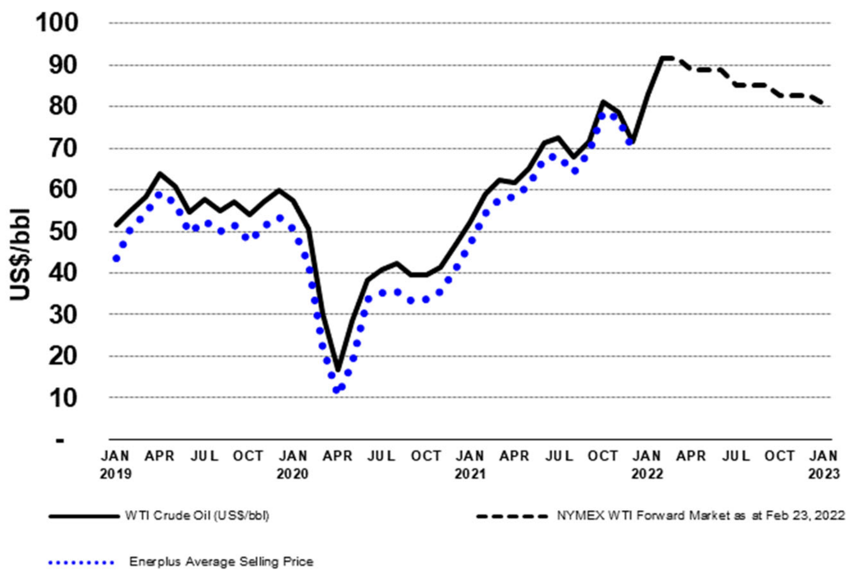
[1] This financial measure is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" section in this MD&A.

NATURAL GAS

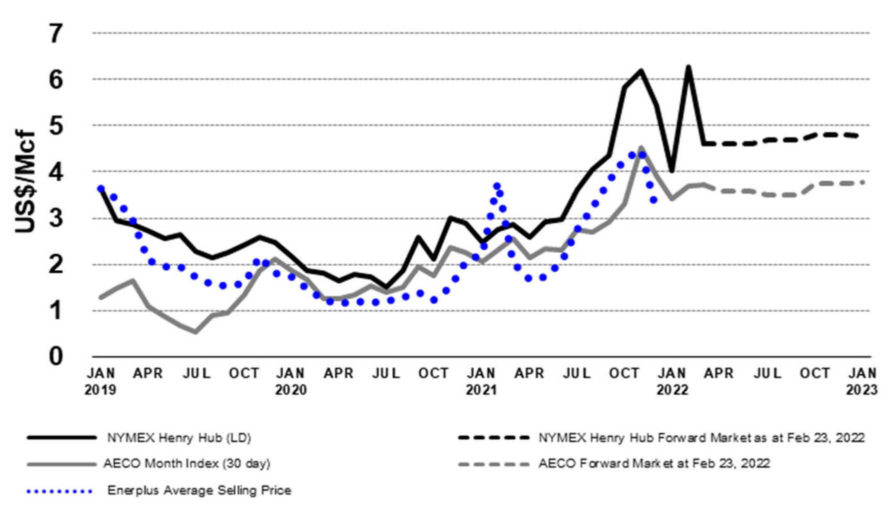
Our realized natural gas price averaged $2.98/Mcf in 2021, a 113% increase from 2020. This increase was greater than the 85% increase in the benchmark NYMEX natural gas price due to regional gas prices in the Northeast U.S. which outperformed the benchmark.

In the Marcellus, we realized an average sales price differential of $0.81/Mcf below NYMEX which was wider than our 2020 realized sales price differential of $0.65/Mcf. The Transco Leidy monthly benchmark differential averaged $0.94/Mcf below NYMEX for 2021, which was weaker than 2020 due to warmer than anticipated weather in the Northeast U.S. in November and December of 2021 resulting in a weaker than forecast local prices for Northeast U.S. natural gas and a much wider differential for 2021. At the same time, NYMEX natural gas prices at Henry Hub settled higher for November and December due to expectations for increased weather demand that failed to materialize. Transco Z6 Non-New York monthly benchmark differentials averaged $0.36/Mcf below NYMEX for 2021 in line with prices from 2020. We expect our Marcellus differential to average $0.75/Mcf below NYMEX in 2022.

Monthly Crude Oil Prices



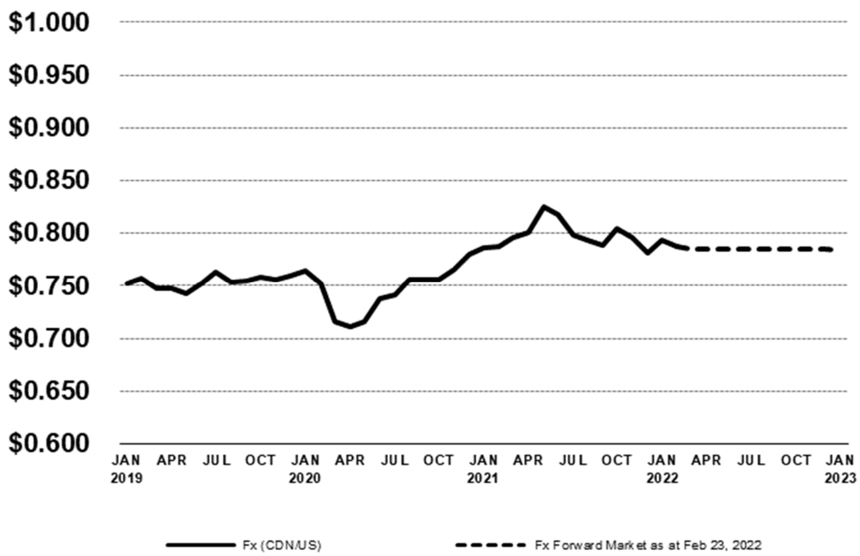
Monthly Natural Gas Prices



FOREIGN EXCHANGE

Fluctuations in the U.S. dollar will impact the amount of our Canadian dollar denominated costs such as Canadian netbacks, capital spending, G&A expenses, and dividends paid to Canadian residents. The U.S. dollar weakened during 2021 as global economies continued to stabilize and crude oil demand continued to recover averaging 0.80 CDN/US compared to 0.75 CDN/US during 2020, the height of the COVID-19 pandemic. The U.S. dollar ended the year at 0.79 CDN/US for both 2021 and 2020. U.S. dollar denominated debt that is held in the Canadian parent entity will continue to result in unrealized foreign exchange gains and losses based on changes in the period end exchange rates. See Notes 2 and 14 to the Financial Statements for further detail.

Monthly CDN/US Exchange Rate



Price Risk Management

We have a price risk management program that considers our overall financial position and the economics of our capital expenditures.

At February 24, 2022, we have commodity derivative contracts in place for approximately 23,200 bbls/day and 7,000 bbls/day of our expected crude oil production for 2022 and 2023, respectively. Our crude oil contracts are predominantly three way collars. The three way collars provide us with exposure to upward price moves; however, the sold put effectively limits our downside protection to the difference between the strike price of the purchased and sold puts. For natural gas, we have contracts in place for 40,000 Mcf/day for January 1 to February 28, 2022 and 100,000 Mcf/day for March 1 to October 31, 2022. Overall, we expect our crude oil and natural gas related commodity derivative contracts to protect a portion of our cash flow from operating activities and adjusted funds flow[1] in 2022 and 2023.

The following is a summary of Enerplus' financial contracts in place at February 24, 2022:

	WTI Crude Oil ($/bbl)(1)(2)(3)				NYMEX Natural Gas ($/Mcf)(2)		
	Jan 1, 2022 – Jun 30, 2022	Jan 1, 2022 – Dec 31, 2022	Jan 1, 2023 – Jun 30, 2023	Jan 1, 2023 – Dec 31, 2023	Jan 1, 2022 – Feb 28, 2022	Mar 1, 2022 – Mar 31, 2022	Apr 1, 2022 – Oct 31, 2022
Swaps							
Volume (bbls/day)	-	-	-	-	-	60,000	40,000
Sold Puts	-	-	-	-	-	$ 4.50	$ 3.40
Collars							
Volume (bbls/day)	12,500	17,000	10,000	2,000	40,000	40,000	60,000
Sold Puts	$ 58.00	$ 40.00	$ 60.00	-	-	-	-
Purchased Puts	$ 75.00	$ 50.00	$ 76.50	$ 5.00	$ 3.43	$ 3.43	$ 3.77
Sold Calls	$ 87.63	$ 57.91	$ 107.38	$ 75.00	$ 6.00	$ 6.00	$ 4.50

(1) The total average deferred premium spent on our outstanding hedges is $1.50/bbl from January 1, 2022 – December 31, 2022 and $1.25/bbl from January 1, 2023 – June 30, 2023.

(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.

(3) Upon closing of the Bruin Acquisition, Bruin's outstanding crude oil contracts were recorded at a fair value liability of $76.4 million. At December 31, 2021, the remaining balance was a liability of $22.8 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 Financial Statements for further details.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)

($ millions)	2021	2020	2019
Realized gains/(losses):			
Crude oil	$ (146.3)	$ 92.8	$ (9.1)
Natural gas	(16.7)	—	20.7
Total realized gains/(losses)	$ (163.0)	$ 92.8	$ 11.6
Unrealized gains/(losses):			
Crude oil	$ (111.6)	$ (19.9)	$ (51.5)
Natural gas	0.2	2.8	(8.0)
Total unrealized gains/(losses)	$ (111.4)	$ (17.1)	$ (59.5)
Total gains/(losses)	$ (274.4)	$ 75.7	$ (47.9)

(Per BOE)	2021	2020	2019
Total realized gains/(losses)	$ (4.84)	$ 3.47	$ 0.39
Total unrealized gains/(losses)	(3.31)	(0.64)	(2.01)
Total commodity derivative instruments gains/(losses)	$ (8.15)	$ 2.83	$ (1.62)

During 2021, Enerplus realized losses of $146.3 million on crude oil contracts and $16.7 million on our natural gas contracts, compared to realized gains of $92.8 million on crude oil contracts and no realized gain or losses on our natural gas contracts in 2020. Realized losses in 2021 on crude oil and natural gas contracts were primarily due to crude oil and natural gas prices rising above the swap level and the sold call strike price on our three way collars.

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

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either an unrealized loss or gain to earnings. At December 31, 2021, the fair value of our crude oil contracts was in a net liability position of $146.7 million (December 31, 2020 – net liability position of $12.3 million). The fair value of our natural gas contracts at December 31, 2021 was in a net asset position of $3.0 million (December 31, 2020 – net asset position of $2.8 million). The change in fair value of our crude oil and natural gas contracts represented unrealized losses of $111.6 million and unrealized gains of $0.2 million, respectively, during 2021 and unrealized losses of $19.9 million and unrealized gains of $2.8 million, respectively, during 2020.

On March 10, 2021, the outstanding crude oil commodity contracts acquired with the Bruin Acquisition were recorded at fair value. Realized and unrealized gains and losses on the acquired contracts are recognized in the Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the closing date of the Bruin Acquisition.

At December 31, 2021, the fair value of our commodity contracts totaled a net liability of $143.7 million. Of this total net liability, $40.2 million related to Bruin contracts, with $22.8 million remaining of the original $76.4 million liability acquired from Bruin. At December 31, 2021, the majority of the outstanding Bruin liabilities have been offset through contracts that limit additional hedging losses to Enerplus during 2022 and partially for 2023. See Note 17 to the Financial Statements for further detail.

Crude oil and natural gas sales

($ millions)	2021	2020	2019
Crude oil and natural gas sales	$ 1,482.6	$ 553.7	$ 945.9

Crude oil and natural gas sales for 2021 totaled $1,482.6 million, an increase of 168% from $553.7 million in 2020. The increase in revenue is a result of the increased production volumes, including the combined impact of the Bruin and Dunn County acquisitions in 2021, as well as higher commodity prices. Refer to the “Pricing” section for further details in this MD&A.

Comparing 2020 to 2019, crude oil and natural gas sales decreased 41% to $553.7 million from $945.9 million as a result of lower commodity prices and a decrease in production volumes. During the second quarter of 2020, certain crude oil and natural gas production was temporarily curtailed and the operated North Dakota drilling and completions program was suspended in response to low commodity prices.

Operating Expenses

($ millions, except per BOE amounts)	2021	2020	2019
Operating expenses	$ 292.4	$ 197.1	$ 219.3
Per BOE	$ 8.69	$ 7.38	$ 7.40

Operating expenses for 2021 were $292.4 million or $8.69 BOE, in line with our revised guidance of $8.73/BOE and representing an increase of $95.3 million or an increase of $1.31/BOE from the prior year. The increase was primarily due to higher U.S. crude oil production as a result of the Bruin and Dunn County acquisitions and increased liquids weighting. In addition, operating expenses increased due to higher well service activity in the second half of 2021 and higher water handling charges as a result of contracts with price escalators linked to WTI crude oil prices, which were triggered in 2021.

Operating expenses for 2020 were $197.1 million or $7.38/BOE, representing a decrease of $22.2 million and a in line with 2019 on a BOE basis. The decrease was largely due to lower fluid handling costs associated with lower production volumes.

2022 Guidance

We expect operating expenses of between $9.50/BOE – $10.50/BOE for 2022, an increase from 2021 due to contract price escalation, increased gas processing due to improved gas capture rates and higher well service activity.

Transportation Costs

($ millions, except per BOE amounts)	2021	2020	2019
Transportation costs	$ 128.3	$ 98.7	$ 109.2
Per BOE	$ 3.81	$ 3.69	$ 3.68

Transportation costs in 2021 were in line with our revised guidance of $3.82/BOE, averaging $3.81/BOE or $128.3 million, compared to $3.69/BOE or $98.7 million in 2020. The increase in transportation costs was primarily a result of increased U.S. production with higher associated transportation costs and additional firm transportation commitments compared to the prior year.

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

Transportation costs in 2020 were $3.69/BOE, consistent with 2019. The overall decrease in transportation costs was primarily a result of lower U.S. production with higher associated transportation costs compared to the same period in the prior year.

2022 Guidance

We expect an increase to transportation expenses of $4.15/BOE for 2022 as a result of increased U.S. production and additional firm transportation commitments.

Production Taxes

($ millions, except per BOE amounts)	2021	2020	2019
Production taxes	$ 102.0	$ 37.4	$ 62.7
Per BOE	$ 3.03	$ 1.40	$ 2.12
Production taxes (% of crude oil and natural gas sales)	6.9%	6.8%	6.6%

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

Production taxes were in line with our revised guidance of 7% for 2021, averaging 6.9% of crude oil and natural gas sales, before transportation. Production taxes of $102.0 million in 2021 increased in comparison to prior years due to higher realized commodity prices and production volumes. Production taxes of $37.4 million in 2020 were lower in comparison to 2019, due to lower realized commodity prices and production volumes.

2022 Guidance

We expect annual production taxes to average 7% in 2022.

Netbacks

The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Year ended December 31, 2021		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	64,479 BOE/day	166,454 Mcfe/day	92,221 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 54.91	$ 3.13	$ 44.04
Operating expenses	(11.89)	(0.21)	(8.69)
Transportation costs	(3.11)	(0.91)	(3.81)
Production taxes	(4.23)	(0.04)	(3.03)
Netback before impact of commodity derivative contracts	$ 35.68	$ 1.97	$ 28.51
Realized hedging gains/(losses)	(6.22)	(0.28)	(4.84)
Netback after impact of commodity derivative contracts	$ 29.46	$ 1.69	$ 23.67
Netback before impact of commodity derivative contracts[1] ($ millions)	$ 840.0	$ 119.9	$ 959.9
Netback after impact of commodity derivative contracts[1] ($ millions)	$ 693.7	$ 103.2	$ 796.9

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

Netbacks by Property Type	Year ended December 31, 2020 Crude Oil	Natural Gas	Total
Average Daily Production	45,277 BOE/day	166,434 Mcfe/day	73,016 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 27.81	$ 1.52	$ 20.72
Operating expenses	(10.91)	(0.27)	(7.38)
Transportation costs	(2.67)	(0.89)	(3.69)
Production taxes	(2.18)	(0.02)	(1.40)
Netback before impact of commodity derivative contracts	$ 12.05	$ 0.34	$ 8.25
Realized hedging gains/(losses)	5.60	-	3.47
Netback after impact of commodity derivative contracts	$ 17.65	$ 0.34	$ 11.72
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 199.7	$ 20.8	$ 220.5
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 292.6	$ 20.8	$ 313.4

Netbacks by Property Type	Year ended December 31, 2019 Crude Oil	Natural Gas	Total
Average Daily Production	46,914 BOE/day	205,832 Mcfe/day	81,219 BOE/day
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Crude oil and natural gas sales	$ 45.12	$ 2.31	$ 31.91
Operating expenses	(11.49)	(0.30)	(7.40)
Transportation costs	(2.80)	(0.82)	(3.68)
Production taxes	(3.56)	(0.02)	(2.11)
Netback before impact of commodity derivative contracts	$ 27.27	$ 1.17	$ 18.72
Realized hedging gains/(losses)	(0.53)	0.28	0.39
Netback after impact of commodity derivative contracts	$ 26.74	$ 1.45	$ 19.11
Netback before impact of commodity derivative contracts(1) ($ millions)	$ 467.1	$ 87.6	$ 554.7
Netback after impact of commodity derivative contracts(1) ($ millions)	$ 457.9	$ 108.4	$ 566.3

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

As a result of the strong commodity price environment, compared to 2020, total netbacks before impact of commodity derivative contracts increased by 335% in 2021 and total netback after the impact of commodity derivative contracts increased by 154% in 2021. During 2021, our crude oil properties accounted for 88% of our netback before impact of commodity derivative contracts and 87% of our netback after the impact of commodity derivative contracts, compared to 91% and 93%, respectively in 2020.

General and Administrative ("G&A") Expenses

Total G&A expenses include cash G&A expenses and share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans"). See Note 13, Note 16 and Note 17 to the Financial Statements for further details.

($ millions)	2021	2020	2019
Cash:			
G&A expense	$ 38.4	$ 33.5	$ 36.9
Share-based compensation expense	6.9	(0.9)	0.5
Non-Cash:			
Share-based compensation expense	13.8	9.7	16.8
Equity swap loss/(gain)	(1.9)	1.0	0.2
G&A expense/(recovery)	(0.4)	(0.2)	0.5
Total G&A expenses	$ 56.8	$ 43.1	$ 54.9

(Per BOE)	2021	2020	2019
Cash :			
G&A expense	$ 1.14	$ 1.26	$ 1.24
Share-based compensation expense	0.20	(0.04)	0.02
Non-Cash:			
Share-based compensation expense	0.41	0.36	0.57
Equity swap loss/(gain)	(0.06)	0.04	0.01
G&A expense/recovery	(0.01)	(0.01)	0.01
Total G&A expenses	$ 1.68	$ 1.61	$ 1.85

Cash G&A expenses were $38.4 million or $1.14/BOE in 2021, in line with our revised guidance of $1.14/BOE. Total cash G&A expenses were higher on a total dollar basis, however, due to increased production, the per BOE basis was lower compared to 2020. Total cash G&A expenses were lower during 2020 due to a combination of salary reductions as well as COVID-19 pandemic government funding, which reimbursed qualifying Canadian employers for a portion of salaries paid.

SBC can be equity settled or cash-settled, depending on the underlying plan to which it relates. Equity settled non-cash SBC was $13.8 million or $0.41/BOE in 2021, compared to $9.7 million or $0.36/BOE in 2020 and $16.8 million or $0.57/BOE in 2019. Performance Share Units ("PSUs"), as one of the equity settled LTI plans, is impacted by performance multipliers. During 2021, the multipliers remained consistent causing the expense to increase compared to 2020 when multipliers were reduced. The equity settled non-cash SBC was higher in 2019 due to higher PSU multipliers.

SBC that is cash-settled was $6.9 million or $0.20/BOE in 2021, compared to a recovery of $0.9 million or $0.04/BOE in 2020. The increase in expense was due to a higher share price during 2021, and the impact this had on our director plans. Similarly, cash SBC expense was higher in 2019 compared to 2020, due to a decrease in our share price during 2020.

Enerplus has hedged a portion of the outstanding cash settled units under our LTI plans. During 2021, an unrealized mark-to-market gain of $1.9 million was recorded on these hedges as a result of the improved share price (2020 – $1.0 million loss; 2019 – $0.2 million loss).

2022 Guidance

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

Interest Expense

Interest on our senior notes and Bank Credit Facility for 2021 totaled $27.4 million, an increase of 32% from $20.7 million in 2020. The increase was primarily due to higher debt levels incurred to fund the Bruin and Dunn County acquisitions, partially offset by the final repayment of our 2009 senior notes and scheduled repayment of our 2012 senior notes, which carry higher interest rates than our Bank Credit Facility and term loan.

Interest on our senior notes and Bank Credit Facility for 2020 of $20.7 million decreased compared to $25.6 million in 2019 due to the repayment of a portion of our 2009 and 2012 senior notes during 2020.

At December 31, 2021, approximately 43% of our debt was based on fixed interest rates and 57% on floating interest rates (December 31, 2020 – 100% fixed), with weighted average interest rates of 4.2% and 1.9%, respectively (December 31, 2020 – 4.4%). See Note 9 to the Financial Statements for further details on our outstanding senior notes.

Foreign Exchange

($ millions)	2021	2020	2019
Realized:			
Foreign exchange loss/(gain) on settlements	$ 3.5	$ 0.8	$ (1.3)
Translation of U.S. dollar cash held in Canada loss/(gain)	(2.3)	(0.9)	6.8
Unrealized loss/(gain)	(8.1)	1.3	(21.9)
Total foreign exchange loss/(gain)	$ (6.9)	$ 1.2	$ (16.4)
CDN/US average exchange rate	0.80	0.75	0.75
CDN/US period end exchange rate	0.79	0.79	0.77

Enerplus recorded a total foreign exchange gain of $6.9 million in 2021, compared to a loss of $1.2 million in 2020 and a gain of $16.4 million in 2019. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies and the translation of our U.S. dollar denominated cash held in Canada, while unrealized 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.

Effective January 1, 2020, we designated outstanding U.S. dollar senior notes as a net investment hedge related to our U.S. operations. At December 31, 2021, $303.8 million of senior notes outstanding and the $400 million term loan were designated as net investment hedges against the investment in our U.S. subsidiary. As a result, unrealized foreign exchange gains and losses on the translation of this U.S. dollar denominated debt are included in Other Comprehensive Income/(Loss). For the year ended December 31, 2021, Other Comprehensive Income/(Loss) included an unrealized gain of $4.1 million on our outstanding U.S. dollar denominated senior notes and our term loan (2020 – $1.8 million gain; 2019 – nil). For the year ended December 31, 2019, the unrealized gains and losses recorded on the translation of our senior notes was included in Consolidated Net Income/(Loss). See Note 2 to the Financial Statements for further details.

Property, Plant and Equipment

($ millions)	2021	2020	2019
Capital spending(1)(2)	$ 302.3	$ 217.2	$ 465.9
Office capital	1.6	2.2	4.4
Sub-total	303.9	219.4	470.3
Bruin Acquisition	$ 520.2	$ —	$ —
Dunn County Acquisition	305.1	—	—
Property and land acquisitions	9.8	7.5	18.4
Property divestments	(112.7)	(4.5)	(7.2)
Sub-total	722.4	3.0	11.2
Total	$ 1,026.3	$ 222.4	$ 481.5

(1) This financial measure, including related guidance, as applicable, is a supplementary financial measure. See “Non-GAAP and Other Financial Measures” section in this MD&A.
(2) Excludes changes in non-cash investing working capital. See Note 20 of the Consolidated Financial Statements for additional information.

2021

Capital spending in 2021 totaled $302.3 million, in line with our revised guidance of $303 million. In 2021, we spent $256.1 million on our U.S. crude oil properties, $13.8 million on our Canadian crude oil properties and $31.0 million on our Marcellus natural gas assets. The increase in capital spending[1] in 2021 compared to 2020 was mainly due to minimal drilling and completions activity in North Dakota during 2020 in response to low crude oil prices as a result of the COVID-19 pandemic. Through our capital program, we added 85.0 MMBOE of gross proved plus probable Canadian NI 51-101 Standards reserves, replacing 204% of our production, including economic factors and technical revisions and before accounting for acquisitions and divestments. Including acquired and divested volumes, we replaced 558% of our 2021 production adding 233.0 MMBOE of gross proved plus probable reserves.

During 2021, we completed the Bruin Acquisition for total cash consideration of $465.0 million or $420.2 million after purchase price adjustments, with $520.2 million allocated to PP&E, excluding the assumed asset retirement obligation. We also completed the Dunn County Acquisition for total cash consideration of $306.8 million, with $305.1 million allocated to PP&E, excluding the assumed asset retirement obligation.

Property divestments were related to the sale of our interest in the Sleeping Giant field in Montana and the Russian Creek area in North Dakota in the Williston Basin, during the fourth quarter of 2021 for total cash consideration of $115.0 million, before purchase price adjustments. After purchase price adjustments and transaction costs, adjusted proceeds of $107.8 million, were all allocated to PP&E, excluding the divested asset retirement obligation. Enerplus may receive up to $5.0 million in additional contingent payments if the WTI oil price averages over $65/bbl in 2022 and over $60/bbl in 2023.

2020

Capital spending in 2020 totaled $217.2 million, including $174.8 million on our U.S. crude oil properties, $17.4 million on our Canadian crude oil properties and $24.8 million on our Marcellus natural gas assets. The decrease in capital spending[1] in 2020 compared to the prior year was mainly due to minimal drilling and completions activity in North Dakota during the second and third quarters of 2020 in response to low crude oil prices as a result of the COVID-19 pandemic and minimal capital activity in the Marcellus. Through our capital program in 2020, we added 16.7 MMBOE of gross proved plus probable Canadian NI 51-101 Standards reserves, replacing 50% of our net production, including economic factors and technical revisions and before accounting for acquisitions and divestments. Excluding economic factors, we replaced 89% net interest total 2020 production and added 29.2 MMBOE of gross proved plus probable reserves.

Property and land acquisitions in 2020 totaled $7.5 million, which included minor acquisitions of leases and undeveloped land. We recorded net divestments of $4.5 million in 2020.

2019

Capital spending in 2019 totaled $465.9 million, including $400.2 million on our U.S. crude oil properties, $28.5 million on our Canadian crude oil properties and $37.2 million on our Marcellus natural gas assets. Through our capital program in 2019, we added 51.0 MMBOE of gross proved plus probable Canadian NI 51-101 Standards reserves, replacing 139% of our 2019 net production, before accounting for acquisitions and divestments.

Property and land acquisitions in 2019 totaled $18.4 million and consisted primarily of undeveloped land in North Dakota. We recorded net divestments of $7.2 million related to the sale of properties in southeastern Saskatchewan.

2022 Guidance

Our capital spending guidance range is $370 million – $430 million for 2022.

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

($ millions, except per BOE amounts)	2021	2020	2019
DD&A expense	$ 271.3	$ 218.1	$ 269.0
Per BOE	$ 8.06	$ 8.16	$ 9.08

DD&A of PP&E is recognized using the unit of production method based on proved reserves. We recorded DD&A of $271.3 million during 2021, an increase compared to $218.1 million in 2020, as a result of higher overall production volumes and the net impact of acquisitions, divestments and previous PP&E impairments.

Impairments

PP&E

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country cost centre basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves ("Standardized Measure"), using constant prices as defined by the SEC guidelines. SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. The Standardized Measure is not related to Enerplus' investment criteria and is not a fair value-based measurement, but rather a prescribed accounting calculation. Impairments are non-cash and are not reversed in future periods under U.S. GAAP.

Trailing twelve month average crude oil and natural gas prices have improved throughout 2021 after falling in 2020 as a result of the impacts of the COVID-19 pandemic. For the twelve months ended December 31, 2021, we recorded a PP&E impairment of $3.4 million related to our Canadian assets. For the twelve months ended December 31, 2020, we recorded a PP&E impairment of $751.7 million (Canadian cost centre: $100.9 million, U.S. cost centre: $650.8 million). There were no impairments recorded in 2019.

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 the duration of 2021. See Note 6 to the Consolidated 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 upcoming year, 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 this MD&A.

The following table outlines the twelve-month average trailing benchmark prices and exchange rates used in our ceiling test at December 31, 2021, 2020 and 2019:

Year	WTI Crude Oil $/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub $/Mcf	Exchange Rate $CDN/$US
2021	$ 66.55	$ 78.15	$ 3.64	0.80
2020	$ 39.54	$ 45.56	$ 2.00	0.75
2019	$ 55.85	$ 66.73	$ 2.58	0.75

Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. Goodwill is stated at cost less impairment and is not amortized or deductible for income tax purposes.

During 2020, we recorded a goodwill impairment of $149.2 million related to our U.S. reporting unit. The impairment was a result of the deterioration in macroeconomic conditions and low commodity prices due to the COVID-19 pandemic, which resulted in a reduction in fair value of the U.S. reporting unit and a full write down of our U.S. goodwill asset. In 2019, we recorded a goodwill impairment of $347.3 million representing the full value of the goodwill attributable to our Canadian reporting unit. At December 31, 2021 and 2020 there was no goodwill 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 our balance sheet is based on management's estimate of our net ownership interest, costs to abandon, reclaim and remediate, the timing of the costs to be incurred in future periods and estimates for inflation. We have estimated the net present value of our asset retirement obligation to be $132.8 million at December 31, 2021, compared to $102.3 million at December 31, 2020. The increase in the net present value is largely due to the additional liability assumed in the connection with the Bruin and Dunn County acquisitions. See Note 3 and Note 10 to the Financial Statements for further information.

During 2021, we spent $13.0 million (2020 – $13.3 million) on our asset retirement obligations. The majority of our abandonment, reclamation and remediation costs are expected to be incurred between 2036 and 2051. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any abandonment, reclamation and remediation costs are anticipated to be funded out of adjusted funds flow[1] and our Bank Credit Facility.

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 twelve months ended December 31, 2021, Enerplus benefitted from $4.6 million (2020 – nil), in government assistance. See Note 10 to the Consolidated Financial Statements for further details.

Leases

Enerplus recognizes Right-Of-Use ("ROU") assets and lease liabilities on the Consolidated Balance Sheet for qualifying leases with a term greater than 12 months. We incur lease payments related to office space, drilling rig commitments, vehicles and other equipment. Total lease liabilities included on our balance sheet are based on the present value of lease payments over the lease term. Total ROU assets included on our balance sheet represent the remaining unamortized amount of our right to use an underlying asset for its remaining lease term. At December 31, 2021 and December 31, 2020 our total lease liability was $28.9 million. At December 31, 2021, our ROU asset was $26.1 million, compared to $25.8 million at December 31, 2020. See Note 11 to the Consolidated Financial Statements for further details.

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

Income Taxes

($ millions)	2021	2020	2019
Current tax expense/(recovery)	$ 2.7	$ (10.7)	$ (25.2)
Deferred tax expense/(recovery)	98.8	(188.3)	61.7
Total tax expense/(recovery)	$ 101.5	$ (199.0)	$ 36.5

In 2021, we recorded a current tax expense of $2.7 million compared to tax recoveries of $10.7 million in 2020 and $25.2 million in 2019. The expense in 2021 related primarily to income generated from U.S. operations. The recovery in 2020 was related to the recognition of our final U.S. Alternative Minimum Tax ("AMT") refund. The recovery in 2019 was related to the favorable settlement of a tax dispute in Canada of $10.5 million and an AMT refund of $10.7 million.

We expect current tax expense of approximately $10 million in 2022.

In 2021, we recorded a deferred income tax expense of $98.8 million compared to a recovery of $188.3 million in 2020 and an expense of $61.7 million in 2019. The expense in 2021 is primarily due to U.S. income generated in 2021. The deferred tax recovery in 2020 was due to net losses in 2020 from non-cash PP&E impairments in both Canada and the U.S. cost centres. The deferred tax expense in 2019 included a $17.1 million expense from the remeasurement of our net Canadian deferred income tax assets for the change in the Alberta corporate income tax rate from 12% to 8%.

We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will not be realized. We have considered available positive and negative evidence including future taxable income and reversing existing temporary differences in making this assessment. This assessment is primarily the result of projecting future taxable income using total proved and probable 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 year ended December 31, 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. Overall, the net deferred income tax asset was $380.9 million at December 31, 2021 (December 31, 2020 – $477.0 million).

Our estimated tax pools at December 31, 2021 are as follows:

Pool Type ($ millions)	2021
U.S.	
Net operating losses and other credits	$ 742
Depletable and depreciable assets	1,010
	1,752
Canada	
Canadian oil and gas property expense	$ 5
Canadian development expense	167
Canadian exploration expense	187
Undepreciated capital costs	253
Non-capital losses and other credits	146
	758
Total tax pools and credits	$ 2,510
Capital losses	$ 848

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage, including commodity price cycles, capital spending levels, acquisition and divestment plans, commodity derivative contracts, share repurchases and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges (“adjusted EBITDA[1]”) ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2021, our senior debt to adjusted EBITDA ratio was 1.0x and our net debt to adjusted funds flow ratio[1] was 0.9x. Although a Non-GAAP measure that is not included in our debt covenants, the net debt to adjusted funds flow ratio[1] is often used by investors and analysts to evaluate our liquidity. Refer to the definitions and footnotes below.

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

Net debt[1] at December 31, 2021 increased to $640.4 million, compared to $295.5 million at December 31, 2020. Total debt was comprised of our senior notes and term loan, totaling $701.7 million, less cash on hand of $61.3 million. The increase was due to funding a portion of the Bruin Acquisition using a $400 million term loan and funding the Dunn County Acquisition by drawing on our Bank Credit Facility. 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 next scheduled senior note repayments of $59.6 million and $20.0 million are due in May 2022 and $21.0 million is due in September 2022, with remaining maturities extending to 2026. At December 31, 2021, we were undrawn on our $900 million Bank Credit Facility. Subsequent to December 31, 2021, Enerplus converted its $400 million term loan into a revolving credit facility with no other amendments.

Our reinvestment rate[1] was 42% for 2021 compared to 82% in 2020. We are committed to free cash flow[1] generation and are targeting a long-term capital spending reinvestment rate[1] of less than 75% of annual adjusted funds flow[1].

During 2021, a total of $153.7 million was returned to shareholders through share repurchases and dividends, compared to $21.9 million in 2020. In 2021, a total of 12,897,721 common shares were repurchased under the NCIB at an average price of $9.55 (CDN$12.06) per share (December 31, 2020 – 340,434 shares, $5.63 (CDN$7.44) per share). Subsequent to December 31, 2021 and up to and including February 23, 2022, we repurchased 2,257,400 common shares under the NCIB at an average price of $11.58 (CDN$14.67) per share, for total consideration of $26.1 million.

For the year ended December 31, 2021, Enerplus increased its quarterly dividend three times by 37% to CDN$0.041 ($0.03) per common share totaling $30.5 million (December 31, 2020 $20.0 – million).

We plan to continue to return capital to our shareholders, including the repurchase of the remaining authorization under the NCIB by the end of July 2022, based on current market conditions. We intend to renew the NCIB in August 2022. Subsequent to December 31, 2021, the Board of Directors also approved a first quarter dividend payment of $0.033 per share to be paid in March 2022. We expect to fund the dividend and share repurchase program through the free cash flow[1] generated by the business.

Our working capital deficiency[1], which we calculate by excluding cash and cash equivalents and current derivative financial assets and liabilities, increased to $239.3 million at December 31, 2021, from $202.6 million at December 31, 2020. Our working capital[1] varies primarily 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[1] program, along with commodity price volatility. We expect to finance our working capital deficiency[1] and ongoing working capital[1] requirements through cash, adjusted funds flow[1] and our Bank Credit Facility. In addition, we have sufficient liquidity to meet our financial commitments for the near term, as disclosed under "Commitments".

During the second quarter of 2021, we increased and extended our senior, unsecured, covenant-based Bank Credit Facility to $900 million from $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 ("SPTs") 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 December 31, 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 Company 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 senior note purchase agreements have been filed under our SEDAR profile at www.sedar.com.

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

The following table lists our financial covenants, as defined by our debt agreements, at December 31, 2021:

Covenant Description		**December 31, 2021**
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	1.0x
Total debt to adjusted EBITDA	4.0x	1.0x
Total debt to capitalization	55%	34%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA[(1)]	3.0x – 3.5x	1.0x
Senior debt to consolidated present value of total proved reserves[(2)]	60%	18%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	27.6x

Definitions

"Senior Debt" is calculated as the sum of drawn amounts on our Bank Credit Facility, outstanding letters of credit and the principal amount of senior notes.

"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, 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 twelve months ended December 31, 2021 was $755.5 million.

"Total Debt" is calculated as the sum of senior debt plus subordinated debt. Enerplus currently does not have any subordinated debt.

"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $823.7 million adjustment related to our adoption of U.S. GAAP.

Footnotes

(1) Senior debt to adjusted EBITDA for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.

(2) Senior debt to consolidated present value of total proved reserves is calculated annually on December 31 based on before tax reserves at forecast prices discounted at 10%.

Counterparty Credit

CRUDE OIL AND NATURAL GAS SALES COUNTERPARTIES

Our crude oil and natural gas receivables are with customers in the oil and gas industry and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. A credit review process is in place to assess and monitor our counterparties' creditworthiness on a regular basis. This process involves reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted, we obtain financial assurances such as letters of credit, parental guarantees or third-party insurance to mitigate a portion of our credit risk. This process is utilized for both our crude oil and natural gas sales counterparties as well as our financial derivative counterparties.

FINANCIAL DERIVATIVE COUNTERPARTIES

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. All of our derivative counterparties are considered investment grade. At December 31, 2021, we had $5.7 million in financial derivative assets offset by $150.3 million of financial derivative liabilities resulting in a net liability position of $144.6 million (December 31, 2020 – assets of $2.8 million, offset by liabilities of $15.1 million, resulting in a net liability position of $12.3 million).

Dividends

($ millions, except per share amounts)	**2021**	**2020**	**2019**
Dividends[(1)]	$ 30.5	$ 20.0	$ 20.9
Per weighted average share (Basic)	$ 0.12	$ 0.09	$ 0.09

(1) Excludes changes in non-cash financing working capital. See Note 20 of the Consolidated Financial Statements for additional information.

During 2021, we declared dividends of CDN$0.15 ($0.12) per weighted average common share totaling $30.5 million (2020 – CDN$0.12 ($0.09) per share and $20.0 million; 2019 – CDN$0.12 ($0.09) per share and $20.9 million).

In 2021, we declared a monthly divided of CDN$0.010 ($0.008 on average) in January through May. In May 2021, we announced a transition to a quarterly dividend of CDN$0.033 ($0.027) per common share starting with our June dividend. The dividend was increased to CDN$0.038 ($0.030) per common share for the dividend declared in August of 2021 and further increased to CDN$0.041 ($0.032) per common share for the dividend declared in November of 2021. Subsequent to December 31, 2021, the Board of Directors approved a first quarter dividend payment of $0.033 per share to be paid in March 2022.

We expect to fund the dividend through the free cash flow[1] generated by the business. The dividend is a part of our strategy to return capital to shareholders. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	2021	2020	2019
Share capital ($ millions)	$ 3,094.1	$ 3,113.8	$ 3,106.9
Common shares outstanding (thousands)	243,852	222,548	221,744
Weighted average shares outstanding – basic (thousands)	251,909	222,503	231,334
Weighted average shares outstanding – diluted (thousands)	259,851	222,503	231,334

For the twelve months ended December 31, 2021, a total of 2,014,193 units vested pursuant to our treasury settled LTI plans (2020 – 2,044,718; 2019 – 1,007,234). In total, 1,140,000 common shares were issued from treasury and $9.4 million was transferred from paid-in capital to share capital (2020 – 1,160,000 and $10.7 million; 2019 – 564,000 and $3.3 million). We elected to cash settle the remaining units related to the required tax withholdings (2021 – $3.6 million, 2020 – $5.6 million, 2019 – $3.7 million).

During the twelve months ended December 31, 2021, we issued 33,062,500 common shares at a price of CDN$4.00 per common share for gross proceeds of $103.4 million (net $99.5 million, after $5.1 million in issue costs, net of $1.2 million in tax) pursuant to a bought deal prospectus offering under our base shelf prospectus. For further details see Note 3 to the Financial Statements.

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 CDN$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.

On August 12, 2021 we received approval from the TSX to commence a NCIB to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. As a result, 12,897,721 common shares were repurchased and cancelled under the NCIB at an average price of $9.55 (CDN$12.06) per share, for total consideration of $123.2 million. Of the amount paid, $128.7 million was charged to share capital and $5.5 million was credited to accumulated deficit. At December 31, 2021, 12,668,090 common shares were available for repurchase under the current NCIB.

Subsequent to December 31, 2021 and up to and including February 23, 2022, we repurchased 2,257,400 common shares under the NCIB at an average price of $11.58 (CDN$14.67) per common share, for total consideration of $26.1 million.

As of February 23, 2021, we had 242,084,979 common shares outstanding. In addition, an aggregate of 11,027,720 common shares may be issued to settle outstanding grants under our share award incentive plan (in the form of PSUs and RSUs), assuming the maximum payout multiplier of 2.0 times for the PSUs. For further details see Note 16 to the Financial Statements.

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

Commitments and Contingencies

We have the following minimum annual contractual commitments:

($ millions)	Total	Minimum Annual Commitment Each Year 2022	2023	2024	2025	2026	Total Committed after 2026
Senior notes(1)	$ 303.8	$ 100.6	$ 80.6	$ 80.6	$ 21.0	$ 21.0	$ —
Term loan(1)	400.0	—	—	400.0	—	—	—
Transportation commitments	545.7	72.2	72.9	73.2	74.0	74.5	178.9
Processing commitments	6.3	1.2	1.2	1.2	1.2	1.2	0.3
Service workover rigs commitments	9.8	7.9	1.9	—	—	—	—
Operating lease obligations	30.6	11.4	10.2	5.9	1.0	0.9	1.2
Total commitments(2)(3)	$ 1,296.2	$ 193.3	$ 166.8	$ 560.9	$ 97.2	$ 97.6	$ 180.4

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) CDN$ commitments have been converted to US$ using the December 31, 2021 foreign exchange rate of 0.79.

In the Marcellus, we have firm transportation agreements in place for approximately 68,500 Mcf/day of gross natural gas volumes, which expire between 2022 and 2036. This includes an agreement for firm pipeline capacity on the Tennessee Gas Pipeline from our Marcellus producing region to downstream connections for 30,000 Mcf/day of gross natural gas volumes until mid-2027, reducing to 15,000 Mcf/day for an additional 9 years, with a total estimated transportation commitment of $69.6 million through 2036. In the Bakken region, we hold firm pipeline capacity to transport a portion of our crude oil production to the U.S. Gulf Coast, which expires in early 2029 as well as mid-2031.

In Canada, we have various firm transportation agreements for approximately 820 BOE/day of our gross crude oil and natural gas production, from 2022 to 2027 as well as 10,500 Mcf/day of our gross natural gas production expiring between 2023 and 2026. We have firm gross natural gas liquids fractionation contracts for 1,125 bbls/day through 2027.

We have firm commitments in place for the operation of service workover rigs for $9.8 million for 2022 to 2023.

Our commitments and contingencies are more fully described in Note 18 to the Financial Statements. Our operating lease obligations are detailed in Note 11 to the Financial Statements.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

	Year ended December 31, 2021			Year ended December 31, 2020		
($ millions, except per unit amounts)	U.S.	Canada	Total	U.S.	Canada	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	42,981	5,533	48,514	30,657	6,024	36,681
Natural gas liquids (bbls/day)	7,500	323	7,823	4,015	484	4,499
Natural gas (Mcf/day)	207,242	8,062	215,304	179,433	11,581	191,014
Total average daily production (BOE/day)	85,021	7,200	92,221	64,578	8,438	73,016
Pricing(1)						
Crude oil (per bbl)	$ 67.47	$ 55.40	$ 66.05	$ 34.44	$ 27.23	$ 33.30
Natural gas liquids (per bbl)	29.42	38.85	29.86	6.75	16.01	7.79
Natural gas (per Mcf)	2.96	3.40	2.98	1.37	1.94	1.40
Property, Plant and Equipment						
Capital and office expenditures	$ 289.5	$ 14.4	$ 303.9	$ 201.1	$ 18.3	$ 219.4
Acquisitions, including property and land	832.8	2.3	835.1	5.5	2.0	7.5
Property divestments	(108.0)	(4.7)	(112.7)	(4.5)	—	(4.5)
Netback Before Impact of Commodity Derivative Contracts(2)						
Crude oil and natural gas sales	$ 1,355.3	$ 127.3	$ 1,482.6	$ 480.8	$ 72.9	$ 553.7
Operating expenses	(250.7)	(41.7)	(292.4)	(155.2)	(41.9)	(197.1)
Transportation costs	(122.2)	(6.1)	(128.3)	(92.2)	(6.5)	(98.7)
Production taxes	(99.9)	(2.1)	(102.0)	(36.6)	(0.8)	(37.4)
Netback before impact of commodity derivative contracts	$ 882.5	$ 77.4	$ 959.9	$ 196.8	$ 23.7	$ 220.5
Other Expenses						
Asset impairment	$ —	$ 3.4	$ 3.4	$ 100.9	$ 650.8	$ 751.7
Goodwill impairment	—	—	—	149.2	—	149.2
Commodity derivative instruments loss/(gain)	—	274.4	274.4	—	(75.7)	(75.7)
General and administrative expense(3)	35.4	21.4	56.8	41.3	1.8	43.1
Current income tax expense/(recovery)	2.7	—	2.7	(10.7)	—	(10.7)

(1) Before transportation costs and the effects of commodity derivative instruments.
(2) This financial measure is a non-GAAP financial measure. See “Non-GAAP and Other Financial Measures” section in this MD&A.
(3) Includes share-based compensation.

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2021	2020	2019
Crude oil and natural gas sales	$ 1,482.6	$ 553.7	$ 945.9
Net income/(loss)	234.4	(693.4)	(204.4)
Per share (Basic)	0.93	(3.12)	(0.88)
Per share (Diluted)	0.90	(3.12)	(0.88)
Adjusted net income(1)	315.7	14.5	184.3
Cash flow from operating activities	604.8	335.9	519.8
Adjusted funds flow(1)	712.4	265.5	535.6
Dividends(2)	30.5	20.0	21.0
Per share (Basic)(2)	0.12	0.09	0.09
Total assets	1,990.1	1,152.4	1,975.2
Total debt	701.8	385.4	467.0
Net debt(1)	640.4	295.5	350.3
Total non-current financial liabilities	759.3	424.6	519.0

(1) This financial measure is a non-GAAP financial measure. See “Non-GAAP and Other Financial Measures” section in this MD&A.
(2) Calculated based on dividends paid and/or payable.

2021 versus 2020

Crude oil and natural gas sales were $1,482.6 million in 2021 compared to $553.7 million in 2020. We reported net income of $234.4 million in 2021 compared to a net loss of $693.4 million in 2020. The increases were due to higher realized commodity prices and increased production from the Bruin and Dunn County acquisitions as well as lower non-cash impairments in 2021 compared to 2020.

Cash flow from operating activities and adjusted funds flow[1] increased to $604.8 million and $712.4 million, respectively, in 2021 from $335.9 million and $265.5 million in 2020. The increase was primarily the result of a $928.8 million increase in crude oil and natural gas sales due to higher realized commodity prices and higher production.

2020 versus 2019

Crude oil and natural gas sales were $553.7 million in 2020 compared to $945.9 million in 2019 due to lower realized commodity prices and decreased production in 2020.

We reported a net loss of $693.4 million in 2020 compared to a net loss of $204.4 million in 2019. The increased loss in 2020 was primarily due to a $751.7 million PP&E impairment and a $149.2 million U.S. goodwill impairment. The net loss in 2019 was due to a $347.3 million Canadian goodwill impairment.

Cash flow from operating activities and adjusted funds flow[1] decreased to $335.9 million and $265.5 million, respectively, in 2020 from $519.8 million and $535.6 million in 2019. The decrease was primarily the result of a $392.2 million decrease in crude oil and natural gas sales due to lower realized commodity prices and lower production, partially offset by a $123.7 million increase in realized commodity derivative gains.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Crude oil and Natural Gas Sales	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2021				
Fourth Quarter	$ 499.7	$ 176.9	$ 0.71	$ 0.68
Third Quarter	421.1	98.1	0.38	0.38
Second Quarter	333.4	(50.9)	(0.20)	(0.20)
First Quarter	228.4	10.3	0.04	0.04
Total 2021	$ 1,482.6	$ 234.4	$ 0.93	$ 0.90
2020				
Fourth Quarter	$ 150.2	$ (161.6)	$ (0.73)	$ (0.73)
Third Quarter	144.2	(84.4)	(0.38)	(0.38)
Second Quarter	88.9	(444.6)	(2.00)	(2.00)
First Quarter	170.4	(2.8)	(0.01)	(0.01)
Total 2020	$ 553.7	$ (693.4)	$ (3.12)	$ (3.12)

During the first quarter of 2021, crude oil and natural gas sales increased due to improvements in commodity prices. During the second quarter of 2021, crude oil and natural gas sales increased due to higher production from the Bruin and Dunn County acquisitions. The net loss in the same period was primarily due to commodity derivative instrument losses as a result of the higher commodity prices as crude oil demand continued to improve. During the second half of 2021, commodity prices continued to increase and additional wells came on production which resulted in higher net income.

During 2020, we reported crude oil and natural gas sales, of $553.7 million. We reported a net loss in 2020 due to numerous PP&E impairments totaling $751.7 million and a goodwill impairment of $149.2 million on our U.S. reporting unit recorded in the twelve months ended December 31, 2020.

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

ENVIRONMENT, SOCIAL AND GOVERNANCE ("ESG")

Enerplus believes that minimizing the environmental impacts of its operations is a foundational tenet of corporate responsibility. Moreover, as the global economy transitions to a lower carbon future, climate related policies and regulations around carbon emissions are becoming increasingly stringent, requiring businesses to adapt to support long-term business resilience. We intend to continue to improve energy efficiencies and proactively manage our environmental impact in compliance with applicable government regulations, including regulations enacted at the provincial, state and federal jurisdictions in which we operate.

Our Board of Directors is responsible for overseeing our ESG initiatives. Specific accountability for our six material focus areas have been mapped to the relevant Board subcommittees, including the Compensation and Human Resources Committee, the Reserves, Safety and Social Responsibility Committee (the "RS&SR Committee") and the Corporate Governance and Nominating Committee. The six material focus areas are:

- Greenhouse Gas ("GHG") Emissions
- Water Management
- Culture
- Community Engagement
- Health and Safety
- Board Constitution and Culture

As part of our continued integration of ESG issues into our business strategy and operations, in 2021 we established targets for reducing GHG emissions intensity and freshwater use. Using 2019 as a baseline, we targeted a 20% reduction of our methane emissions per BOE by the end of 2022. We continued to progress towards our long-term emissions reduction target of reducing our Scope 1 and Scope 2 emissions by 50% by 2030 relative to our 2019 baseline. During 2021, we have reduced our methane emissions intensity by over 20%, one year ahead of target and reduced 2021 GHG emissions intensity by approximately 25%, based on preliminary estimates. Finalized emissions will be available in our annual ESG Report and Data Tables, expected to be published later in 2022.

In 2021, we targeted a reduction in freshwater use per well completion in the Fort Berthold Indian Reserve ("FBIR") by 25%, compared to 2019. We ended 2021 using, on average, 31% less freshwater per well completion in North Dakota, compared to 2019.

We set a Health & Safety target of reducing our Lost Time Injury Frequency ("LTIF") by 25%, on average, from 2020 to 2023, relative to a 2019 baseline. In 2021, we reported an LTIF of 0.00 injuries per 200,000 worker hours, down from 0.08 in 2019. We will continue to update the market as we progress closer to the end of our 2023 target. We are pleased to announce our 2021 LTIF was the best safety performance in our organization's history.

We have integrated the assets acquired through the Bruin Acquisition into our existing ESG strategy throughout 2021. More information will be available with the publication of our 2022 ESG Report later in the year.

We have a Health & Safety Policy ("H&S Policy") and an Environmental, Social and Governance Policy ("ESG Policy"), which articulate our commitment to health and safety, community engagement, environmental and regulatory compliance, and social and governance practices. Our Board of Directors and President & Chief Executive Officer are ultimately accountable for ensuring compliance with these policies. The RS&SR Committee of our Board of Directors is responsible for overseeing our H&S performance. The Board of Directors are responsible for overseeing our ESG performance and strategy. This ensures there are adequate systems in place to support ongoing compliance, and to plan the Company's activities in a safe, socially responsible and sustainable manner.

The RS&SR Committee regularly reviews health, safety, environmental and regulatory updates, and risks. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and we have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations. However, increased capital and operating costs may be incurred if regulations in Canada or the U.S. impose more stringent compliance requirements.

Annually, we publish an ESG Report in accordance with the Sustainability Accounting Standards Boards ("SASB") materiality metrics, the Global Reporting Initiative ("GRI") Core option, and the International Petroleum Industry Environmental Conservation Association's ("IPIECA") "Oil and gas industry guidance on voluntary sustainability reporting" (a joint publication with the American Petroleum Institute and the International Association of Oil & Gas Producers). In 2021, in conjunction with our ESG Report, we published our inaugural Task Force on Climate Related Financial Disclosure ("TCFD") Aligned Reporting Table. The report summarizes our environmental, safety, social responsibility and governance performance, and can be found on our website at www.enerplus.com.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with U.S. GAAP requires management to make certain judgments and estimates. Due to the timing of when activities occur compared to the reporting of those activities, management must estimate and accrue operating results and capital expenditures. Changes in these judgments and estimates could have a material impact on our financial results and financial condition.

Crude Oil and Natural Gas Properties and Reserves

Enerplus follows the full cost method of accounting for crude oil and natural gas properties. The process of estimating reserves is critical in determining several accounting estimates including the Company's depletion, ceiling test, valuation allowance on deferred income tax assets, gain or loss calculations that may arise upon disposition of crude oil and natural gas properties and purchase equations associated with business combinations. The estimation of crude oil and natural gas reserves and the related present value of future cash flows involves the use of independent reservoir engineering specialists and numerous estimates and assumptions including forecasted production volumes, forecasted operating, royalty and capital cost assumptions and assumptions around commodity pricing. Estimating reserves requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and natural gas prices, operating costs and royalty burdens change. Reserves estimates impact net income through depletion, the determination of asset retirement obligation and the application of impairment tests. Revisions or changes in reserves estimates can have either a positive or a negative impact on net income.

Asset Impairment

Ceiling Test

Under the full cost method of accounting for PP&E, we are subject to quarterly calculations of a ceiling or limitation on the amount of our crude oil and natural gas properties that can be capitalized on our balance sheet by cost centre. If the net capitalized costs of our crude oil and natural gas properties exceed the cost centre ceiling, we are subject to a ceiling test write-down to the extent of such excess. These write-downs reduce net income and impact shareholders' equity in the period of occurrence and result in lower depletion expense in future periods. The volume and discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. However, the associated prices of crude oil and natural gas that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that we use the unweighted arithmetic average price of crude oil and natural gas as of the first day of each month for the 12-month period ending at the balance sheet date. If average crude oil and natural gas prices decline, or if we have downward revisions to our estimated proved reserves, it is possible that write-downs of our crude oil and natural gas properties could occur in the future. Under U.S. GAAP impairments are not reversed in future periods.

Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net assets acquired. Goodwill is allocated to reporting units and is assessed for impairment at least annually. To assess impairment, the Company first evaluates qualitative factors, such as industry and market considerations and overall financial performance, to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value including goodwill, a quantitative impairment test is performed. If the carrying amount of the reporting unit exceeds its related fair value, goodwill is written down to the reporting unit's fair value. The fair value used in the impairment test is based on estimates of discounted future cash flows which involve assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates. At December 31, 2020 and 2021, there was no goodwill on our Condensed Consolidated Balance Sheet.

Income Taxes

Management makes certain estimates in calculating deferred tax assets and liabilities, as well as income tax expense. These estimates often involve judgment regarding differences in the timing and recognition of revenue and expense for tax and financial reporting purposes as well as the tax basis of our assets and liabilities at the balance sheet date before tax returns are completed. Additionally, we must assess the likelihood we will be able to recover or utilize our deferred tax assets. We must record a valuation allowance against a deferred tax asset where all or a portion of that asset is not expected to be realized. In evaluating whether a valuation allowance should be applied, we consider evidence such as future taxable income, among other factors, both positive and negative. This determination involves numerous judgments and assumptions and includes estimating factors such as commodity prices, production and other operating conditions. If any of those factors, assumptions or judgments change, the deferred tax asset could change, and in particular decrease in a period where we determine it is more likely than not that the asset will not be realized. Alternatively, a valuation allowance may be reversed where it is determined it is more likely than not that the asset will be realized.

Asset Retirement Obligation

Management calculates the asset retirement obligation based on estimated costs to abandon, reclaim and remediate its ownership interest in all wells, facilities and pipelines, the estimated timing of the costs to be incurred in future periods and the appropriate credit adjusted risk free rate. The fair value estimate is capitalized to PP&E as part of the cost of the related asset and depleted over its useful life. There are uncertainties related to asset retirement obligations and the impact on the financial statements could be material as the eventual timing and costs for the obligations could differ from our estimates. Factors that could cause our estimates to differ include any changes to laws or regulations, reserves estimates, costs and technology.

Business Combinations

Management makes various assumptions in determining the fair value of any acquired company's assets and liabilities in a business combination. The most significant assumptions and judgments made relate to the estimation of the fair value of the crude oil and natural gas properties. To determine the fair value of these properties, we, and independent evaluators, estimate crude oil and natural gas reserves and future prices of crude oil and natural gas.

Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates.

The fair value of commodity contracts and the equity swaps is estimated based on commodity and option pricing models that incorporate various factors including forecasted commodity prices, volatility and the credit risk of the entries party to the contract. Changes and variability in commodity prices over the term of the term of the contracts can result in material differences between the estimated fair value at a point in time and the actual settlement amounts. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates, discount rates used to present value the instrument and counterparty credit risk.

RECENT U.S. GAAP ACCOUNTING AND RELATED PRONOUNCEMENTS

Refer to Note 2 in our Financial Statements for Standards and Interpretations that were issued but not yet effective at December 31, 2021.

RISK FACTORS AND RISK MANAGEMENT

COVID-19 Risks

The ongoing COVID-19 pandemic, as well as governmental authorities response thereto, has resulted in, and continues to result in, among other things: increased volatility in financial markets, including credit markets and foreign currency and interest exchange rates; disruptions to global supply chains; labour shortages; reductions in trade volumes; temporary operational restrictions, quarantine orders, business closures and travel bans; an overall slowdown in the global economy; political and economic instability; and civil unrest.

We are also subject to risks relating to the health and safety of our personnel, including the potential for a slowdown or temporary suspension of our operations in locations impacted by an outbreak or further regulatory changes. Such a suspension in operations could also be mandated by governmental authorities in response to the COVID-19 pandemic. This would negatively impact our production volumes, which could adversely impact our business, financial condition and results of operations.

Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, natural gas liquids, and natural gas production. These prices have fluctuated widely in response to a variety of factors including:

- global and domestic supply and demand of crude oil, natural gas and natural gas liquids
- actions taken by OPEC or non-OPEC members to set, maintain or alter production levels
- the ability to export from North America
- geopolitical uncertainty
- sustained pandemics or epidemics, including the ongoing COVID-19 pandemic, or other epidemics that disrupt economies, whether local or global, impacting supply, demand and prices for crude oil, natural gas liquids and natural gas
- global gross domestic product growth
- the level of consumer demand including demand for different qualities and types of crude oil, natural gas liquids and natural gas
- the production and storage levels of North American crude oil, natural gas and natural gas liquids
- supply chain challenges and disruptions
- weather conditions
- proximity of reserves and resources to, and capacity of, transportation facilities, and the availability of refining, processing and fractionation capacity
- the effect of world-wide energy conservation and greenhouse gas reduction measures
- the price and availability of alternative fuels
- existing and proposed changes to government regulations and policy decisions, including moratoriums with respect thereto

A future decline in crude oil or natural gas prices may have a material adverse effect on our operations and cash flows, financial condition, borrowing ability, levels of reserves and resources and the level of capital expenditures available for the development of our crude oil and natural gas reserves or resources. Certain oil or natural gas wells may become or remain uneconomic to produce if commodity prices are low, thereby impacting our production volumes, or our desire to market our production in when market conditions are less satisfactory for Enerplus. Furthermore, we may be subject to the decisions of third party operators or to legislative decisions by regional governments who, independently and using different economic parameters, may decide to curtail or shut-in jointly owned production or to mandate industry-wide production curtailments.

We may use financial derivative instruments and other commodity derivative mechanisms to help limit the adverse effects of crude oil, natural gas liquids, and natural gas price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. At February 24, 2022, we have hedged approximately 23,200 bbls/day and 7,000 bbls/day, respectively, of our expected crude oil production for 2022 and 2023, 40,000 Mcf/day of natural gas production for January 1 to February 28, 2022 and 100,000 Mcf/day for March 1 to October 31, 2022, at price levels disclosed in the “Price Risk Management” section above. Refer to the “Price Risk Management” section for further details on our price risk management program.

Risk of Increasing Attention to ESG Matters

Companies across all industries are facing increasing scrutiny from stakeholders related to their ESG practices. These standards are evolving, and if we fail to comply with these standards or are perceived to have not responded appropriately to these standards, regardless of whether there is a legal requirement to do so, we may suffer from reputational damage and the business, financial condition, and/or stock price could be materially and adversely affected. Increasing attention to climate change, increasing societal expectations on companies to address climate change-related targets, and potential consumer use of substitutes to fossil-fuel energy commodities may result in increased costs, reduced demand for hydrocarbon products, reduced profits, increased investigations and litigation, and negative impacts to our stock price and access to capital markets. Increasing attention to climate change-related targets and expected actions, for example, may result in demand shifts for hydrocarbon products and additional governmental investigations and private litigation against Enerplus.

Risks Relating to Climate Change

Enerplus is subject to climate change related risks which are generally grouped into two categories: physical risks and transition risks. Physical risks include the impact that a change in climate could have on our operations, including limited water availability, severe weather causing flooding, prolonged drought and/or wildfires. These events may increase the cost of water, energy, insurance or capital projects, impacting our profitability. The physical risks of climate change may also result in operational delays, depending on the nature of the event. Enerplus does not believe that its current or near-term operations expose it to any particular physical risks which differ from those facing a typical North American onshore oil and gas producer, and currently cannot predict or quantify the potential financial impact of any such risks.

Transition risk is broader and relates to the consequences of a global transition to reduced carbon, including the risk of regulatory and policy change and reputational concerns. The global push to meet net zero emission targets by 2050 increases the risk of potentially burdensome regulatory and/or policy changes from governments, some of which could have a direct, negative impact on Enerplus should they impede access to service providers, including but not limited to debt holders, insurers, and the investment community. In addition, as a result of these regulations and policies, Enerplus could also have stranded assets, i.e. be unable to obtain value for, or from, its reserves.

More specific concerns of the fossil fuels, for the industry relate to GHG emissions, including methane, as well as water and land use. More stringent legislation or regulations in the United States and Canada, relative to other jurisdictions, including requirements to significantly reduce GHG emissions, water consumption or setback requirements for facilities and wells, could result in increased costs and competitive disadvantages. In addition, a potential increase in capital expenditures, operating expenses, abandonment and reclamation obligations or the loss of operating licenses, any of which may not be recoverable in the marketplace, could result in operations or growth projects becoming less profitable, uneconomic, or result in our inability to continue development of assets.

There is also a risk that financial institutions will adopt, or be pressured, or be required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector; both the Bank of Canada and the Federal Reserve of the United States have joined the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. As a result of new initiatives, we could be required to adopt new technologies, and make a significant investment in capital resources. These initiatives could also result in additional costs if climate-related targets are not achieved, therefore negatively impacting our results and economics.

There is also a reputational risk associated with climate change, which considers the public perception of Enerplus' role in the transition to a low carbon economy. We seek to mitigate this risk through a strong ESG program with six material focus areas which are overseen by our Board of Directors and applicable Board subcommittees. Our strategy is to be a responsible operator – in the eyes of our shareholders, employees, contractors, regulators, lenders, communities and the general public. Despite these efforts, activities undertaken directly by Enerplus or its employees in operating its business, or by others in industry, could adversely affect Enerplus' reputation. If our reputation, or the oil and gas industry in general, is diminished, it could result in: the loss of employees or revenue; delays in regulatory approvals; increased operating, capital, financing and regulatory costs; reduced shareholder confidence and negative stock price movement; negative relationships with Indian Reservations and Indigenous groups; or a loss of public support in general.

Regulatory Risk and Greenhouse Gas Emissions

Government royalties, environmental laws and regulatory requirements can have a significant financial and operational impact on us. As an oil and gas producer, we operate under federal, provincial, state, tribal and municipal legislation and regulation that govern such matters as royalties, land tenure, prices, production rates, various environmental protection controls, well and facility design and operation, income taxes and the exportation of crude oil, natural gas and other products. We may be required to apply for regulatory approvals in the ordinary course of business. To the extent that we fail to comply with applicable government regulations or regulatory approvals, we may be subject to compliance and enforcement actions that are either remedial or punitive to deter future noncompliance. Such actions include fines or fees, notices of noncompliance, warnings, orders, curtailment, administrative sanctions and prosecution.

Government regulations may be changed from time to time in response to economic, political or socioeconomic conditions, including the election of new state, provincial or federal leaders. Additionally, our entry into new jurisdictions or adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. U.S. federal and state and Canadian federal and provincial continue to scrutinize emissions, as well as the usage and disposal of chemicals and water used in fracturing procedures in the oil and gas industry; certain states have called for bans on oil and gas drilling using hydraulic fracturing and the new U.S. administration has taken actions towards fulfilling its initiative of curtailing hydraulic fracturing of federal lands. Additionally, various levels of U.S. and Canadian governments are considering or have implemented legislation to reduce emissions of greenhouse gases, including volatile organic compounds ("VOC") and methane gas emissions.

The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations could negatively impact the development of crude oil and natural gas properties and assets, reduce demand for crude oil and natural gas or impose increased costs on oil and gas companies including taxes, fees or other penalties.

Although we have no control over these regulatory risks, we continuously monitor changes in these areas by participating in industry organizations, conferences, exchanging information with third party experts and employing qualified individuals to assess the impact of such changes on our financial and operating results. Accordingly, while we continue to prepare to meet the potential requirements at each of the provincial, state and federal levels, the actual cost impact and its materiality to our business remains uncertain.

Risk of Increased Capital or Operating Costs

Higher capital or operating costs associated with our operations will directly impact our capital efficiencies and cash flow. Capital costs of completions, specifically the costs of steel, proppant, pumper services, and operating costs such as electricity, chemicals, supplies, processing charges, energy services and labour costs, are a few of the costs that are susceptible to material fluctuation. Although we have a portion of our current capital and operating costs protected with existing agreements, changing regulatory conditions, such as potential new or revised regulations in the U.S. requiring certain raw materials, such as steel, for use on certain projects to be sourced from the U.S., or that goods and/or services be procured from specific vendors or classes of vendors on certain projects, and other supply chain challenges or disruptions, may result in higher than expected supply costs. Additionally, we have certain service contracts tied to inflationary measure benchmarks (such as the consumer price index and WTI crude oil price), which have increased and could further increase its operating costs should the benchmarks rise significantly.

Access to Field Services

Our ability to drill, complete and tie-in wells in a timely manner may be impacted by our access to service providers and supplies. Service providers, including those we rely on, are also in a highly competitive environment that is impacted by worker availability, commodity prices and global supply inventories. Where worker availability is impacted by shortages, due to location or pandemic related issues, for example, some may choose or be required to streamline or discontinue their business, further reducing the supply of vendors and potentially increasing the competition for service/supplies, and thereby the costs to producers. Activity levels in each area may limit our access to these resources, restricting our ability to execute our capital plans in a timely manner. In addition, field service costs are influenced by market conditions and therefore can become cost prohibitive.

Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services through 2023, access to field services and supplies in other areas of our business will continue to be subject to market availability.

Anticipated Benefits of Acquisitions or Divestments

From time to time, we may acquire additional crude oil and natural gas properties and related assets. Achieving the anticipated benefits of such acquisitions will depend in part on successfully consolidating functions and integrating operations, procedures, and personnel in a timely and efficient manner, as well as our ability to realize the anticipated growth opportunities from combining and integrating the acquired assets and properties into our existing business. These activities will require the dedication of substantial management effort, time, capital, and other resources, which may divert management's focus, capital and other resources from other strategic opportunities and operational matters during this process. The risk factors specified in this MD&A relating to the crude oil and natural gas business and our operations, reserves and resources apply equally to future properties or assets that we may acquire. We conduct due diligence in connection with acquisitions, but there is no assurance that we will identify all the potential risks and liabilities related to such properties.

When acquiring assets, we are subject to inherent risks associated with predicting the future performance of those assets. We may make certain estimates and assumptions respecting the characteristics of the assets we acquire, that may not be realized over time. As such, assets acquired may not possess the value we attribute to them, which could adversely impact our future cash flows. To the extent that we make acquisitions with higher growth potential, the higher risks often associated may result in increased chances that actual results may vary from our initial estimates. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods, approaches, and assumptions than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments. There is also no assurance that the acquired assets will be viewed favourably by our investors and could result in a negative effect to the price of our common shares.

Certain acquisitions, and in particular acquisitions of higher risk/higher growth assets and the development of those acquired assets, may require capital expenditures and we may not receive cash flow from operating activities from these acquisitions for several years, or in amounts less than anticipated. Accordingly, the timing and amount of capital expenditures may adversely affect our cash flow.

We may also seek to divest of properties and assets from time to time. These divestments may consist of non-core properties or assets, or may consist of assets or properties that are being monetized to fund alternative projects or development or debt repayments. There can be no assurance that we will be successful, that we will realize the amount of desired proceeds, or that such divestments will be viewed positively by the financial markets. Divestments may negatively affect our results of operations or the trading price of our common shares. In addition, although divestments typically transfer future obligations to the buyer, we may not be exempt from certain future obligations, including abandonment, reclamation, and/or remediation if applicable, which may have an adverse effect on our operations and financial condition.

On February 2, 2022, we announced our plan to initiate a divestment process for our Canadian assets. There is no certainty, nor can we provide any assurance, that this process will be successful or that we will be able to divest of our Canadian assets for consideration or other terms satisfactory to us or within the expected timeline.

Access to Capital Markets

Our access to capital has allowed us to fund a portion of our acquisitions and development capital program through issuance of equity and debt in past years. Continued access to capital is dependent on our ability to optimize our existing assets and to demonstrate the advantages of the acquisition or development program that we are financing at the time, as well as investors' view of the oil and gas industry overall. We may not be able to access the capital markets in the future on terms favorable to us, or at all. Our continued access to capital markets is dependent on corporate performance and investor perception of future performance (both corporately and for the oil and gas sector in general).

We are required to assess our foreign private issuer ("FPI") status under U.S. securities laws on an annual basis. If we lose our FPI status, we may have restricted access to capital markets for a period of time until the required approvals are in place from the SEC.

Access to Transportation and Processing Capacity

Market access for crude oil, natural gas liquids and natural gas production in the U.S. and Canada is dependent on our ability, and the ability of our buyers as applicable, to obtain transportation capacity on third party pipelines and rail as well as access to processing facilities. As production increases in the regions where we operate, it is possible production may exceed the existing capacity of the gathering, pipeline, processing or rail infrastructure. While third party pipelines, processors and independent rail operators generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of capacity. There are occasionally operational reasons for curtailing transportation and processing capacity. Accordingly, there can be periods where transportation and processing capacity is insufficient to accommodate all the production from a given region, causing added expense and/or volume curtailments for all shippers. Our assets are concentrated in specific regions where government or other third parties could limit or ban the shipping of commodities by truck, pipeline or rail. Special interest groups and/or social instability could also prevent access to leased land or continue their opposition to infrastructure development, at either the regulatory or judicial level, including the ongoing matters with respect to DAPL, resulting in operational delays, or even the cancellation of construction of the required infrastructure, or the shutdown of already operating infrastructure projects, further impeding our ability to operate, produce and market our products. Additionally, the transportation of crude oil by rail has been under closer scrutiny by government regulatory agencies in Canada and the U.S. over the past few years. As a result, transporting crude oil by rail may carry a higher cost versus traditional pipeline infrastructure or other means of transporting production.

We monitor this risk for both the short and longer term through dialogue and review with the third party pipelines and other market participants. Where available and commercially appropriate, given the production profile and commodity, we attempt to mitigate transportation and processing risk by contracting for firm pipeline or processing capacity or using other means of transportation, including trucking or selling to third parties that have access to pipeline or rail capacity.

Risk of Curtailed or Shut-in Production

Should we be required to curtail or shut-in production as a result of low commodity prices, environmental regulation, government regulation or third party operational practices, it could result in a reduction to cash flow and production levels and may result in additional operating and capital costs for the well to achieve prior production levels. In addition, curtailments or shut-ins may cause damage to the reservoir and may prevent us from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. Combined with the ongoing volatility in commodity prices, any shortage in pipeline infrastructure in producing regions where we operate may result in discounted prices and an ongoing risk of price-related production curtailments.

Production Replacement Risk

Oil and natural gas reserves naturally deplete as they are produced over time. Our ability to replace production depends on our success in acquiring new land, reserves and/or resources and developing existing reserves and resources. Acquisitions of oil and gas assets will depend on our assessment of value at the time of acquisition and ability to secure the acquisitions generally through a competitive bid process.

Acquisitions and our development capital program are subject to investment guidelines, due diligence and review. Major acquisitions and our annual capital development budget are approved by the Board of Directors and where appropriate, independent reserve engineer evaluations are obtained.

Oil and Gas Reserves and Resources Risk

The value of our company is based on, among other things, the underlying value of our oil and gas reserves and resources. Geological and operational risks along with product price forecasts can affect the quantity and quality of reserves and resources and the cost of ultimately recovering those reserves and resources. Lower crude oil, natural gas liquids, and natural gas prices along with lower development capital spending associated with certain projects may increase the risk of write-downs for our oil and gas property investments. Changes in reporting methodology as well as regulatory practices can result in reserves or resources write-downs.

Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as evaluate or audit the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with Canadian NI 51-101 Standards. For U.S. GAAP accounting purposes, our proved reserves are estimated to be technically the same as our proved reserves prepared under Canadian NI 51-101 Standards and have been adjusted for the effects of SEC constant prices. Independent reserves evaluations have been conducted on approximately 98% of the total proved plus probable net present value (discounted at 10% and using Canadian NI 51-101 Standards) of our reserves at December 31, 2021. McDaniel & Associates Consultants Ltd. (“McDaniel”) evaluated 100% of our Canadian reserves. McDaniel also evaluated 100% of the reserves associated with our U.S. tight oil assets. Netherland, Sewell & Associates, Inc. (“NSAI”) evaluated 100% of our U.S. Marcellus shale gas assets.

The evaluation of best estimate development pending contingent resources associated with our North Dakota assets was conducted by Enerplus’ qualified reserves evaluators and audited by McDaniel. NSAI evaluated our Marcellus shale gas best estimate development pending contingent resources.

The RS&SR Committee of the Board of Directors and the Board of Directors has reviewed and approved the reserves and resources reports of the independent evaluators.

Risk of Impairment of Oil and Gas Properties and Deferred Tax Assets

Under U.S. GAAP, the net capitalized cost of crude oil and natural gas properties, net of deferred income taxes, is limited to the present value of after-tax future net revenue from proved reserves, discounted at 10%, and based on the unweighted average of the closing prices for the applicable commodity on the first day of the twelve months preceding the issuer’s reporting date. The amount by which the net capitalized costs exceed the discounted value will be charged to net income.

Under U.S. GAAP, the net deferred tax asset is limited to the estimate of future taxable income resulting from existing properties. We estimate future taxable income based on before-tax future net revenue from proved plus probable reserves, undiscounted, using forecast prices, and adjusted for other significant items affecting taxable income. The amount by which the gross deferred tax assets exceed the estimate of future taxable income will be charged to net income, however these amounts can be reversed in future periods if future taxable income increases.

We recorded an impairment of $3.4 million related to our Canadian assets in 2021. In 2020, we recorded an impairment of $751.7 million (Canadian cost centre: $100.9 million, U.S. cost centre $650.8 million) on our crude oil and natural gas assets. There were no crude oil and natural gas assets impairments recorded in 2019. No valuation allowance was recorded in 2021. In 2020, we reversed our valuation allowance of $11.5 million recorded in 2019 against a portion of our Canadian deferred income tax asset, as projected future taxable income in Canada was sufficient to recognize these assets. No valuation allowance was recorded against our U.S. deferred income tax asset in 2020 and 2019. There is a risk of impairment on our oil and gas properties, and deferred tax asset if commodity prices weaken, costs increase, or if there is a downward revision to reserves. Please refer to the “Impairments” and “Income Taxes” sections of the MD&A and Notes 5 and 15 of the Financial Statements for further details.

Changes in Income Tax and Other Laws

Income tax, other laws or government incentive programs relating to the oil and gas industry may change in a manner that adversely affects us or our security holders. Canadian, U.S. and foreign tax authorities may interpret applicable tax laws, tax treaties or administrative positions differently than we do or may disagree with how we calculate our income for tax purposes in a manner which is detrimental to us and our security holders.

We monitor developments with respect to pending legal changes and work with the industry and professional groups to ensure that our concerns with any changes are made known to various government agencies. We obtain confirmation from independent legal counsel and advisors with respect to the interpretation and reporting of material transactions.

Counterparty and Joint Venture Credit Exposure

We are subject to the risk that the counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements as a result of liquidity requirements or insolvency. Low crude oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure of our counterparties to perform their financial or operational obligations may adversely affect our operations and financial position. In addition to the usual delays in payment by purchasers of crude oil and natural gas, payments may also be delayed by, among other things: (i) capital or liquidity constraints experienced by our counterparties, including restrictions imposed by lenders; (ii) accounting delays or adjustments for prior periods; (iii) delays in the sale or delivery of products or delays in the connection of wells to a gathering system; (iv) adverse weather conditions, such as freezing temperatures, storms, flooding and premature thawing; (v) blow-outs or other accidents; or (vi) recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for these expenses. Any of these delays could reduce the amount of our cash flow and the payment of cash dividends to our shareholders in a given period and expose us to additional third-party credit risks.

A credit review process is in place to assess and monitor our counterparties' credit worthiness on a regular basis. This includes reviewing and ratifying our corporate credit guidelines, assessing the credit ratings of our counterparties and setting exposure limits. When warranted we attempt to obtain financial assurances such as letters of credit, parental guarantees, or third-party insurance to mitigate our counterparty risk. In addition, we monitor our receivables against a watch list of publicly traded companies that have high debt-to-cash flow ratios or fully drawn bank facilities and, where possible, take our production in kind rather than relying on third party operators. In certain instances, we may be able to aggregate all amounts owing to each other and settle with a single net amount.

See the "Liquidity and Capital Resources" section for further information.

Risk of Exceeding Debt Covenants

Declines or continued volatility in crude oil and natural gas prices may result in a significant reduction in earnings or cash flow, which could lead us to increase amounts drawn under our Bank Credit Facility in order to carry out our operations and fulfill our obligations. Significant reductions to cash flow, significant increases in drawn amounts under the Bank Credit Facility, or significant reductions to proved reserves may result in us breaching our debt covenants under the Bank Credit Facility, senior notes and term loan. If a breach occurs, there is a risk that we may not be able to negotiate covenant relief with one or more of our lenders under the Bank Credit Facility, senior notes or term loan. Failure to comply with debt covenants, or negotiate relief, may result in our indebtedness under the credit facility, senior notes or term loan becoming immediately due and payable, which may have a material adverse effect on our operations and financial condition.

Risk of Insufficient Liquidity

Although we believe that our existing credit facility, senior notes and term loan are sufficient, there can be no assurance that the current amount will continue to be available, or will be adequate for our financial obligations, or that additional funds can be obtained as required or on terms which are economically advantageous to Enerplus. The amounts available under the credit facility, senior notes and term loan may not be sufficient for future operations, or we may not be able to renew our Bank Credit Facility or term loan or obtain additional financing on attractive economic terms, if at all. Subsequent to December 31, 2021, we converted our term loan to a revolving credit facility, which matures on March 10, 2024. The Bank Credit Facility is generally available on a four-year term, extendable each year with a bullet payment required at the end of four years if the facility is not renewed. We renewed our Bank Credit Facility in the second quarter of 2021, incorporating ESG-linked incentive pricing terms, and if the sustainability performance targets are not met, may result in higher future borrowing costs. The Bank Credit Facility currently expires on October 31, 2025. There can be no assurance that such a renewal will be available on favourable terms or that all the current lenders under the facility will participate or renew at their current commitment levels. If this occurs, we may need to obtain alternate financing. Any failure of a member of the lending syndicate to fund its obligations under the Bank Credit Facility or to renew its commitment in respect of such Bank Credit Facility, or failure by Enerplus to obtain replacement financing or financing on favourable terms, may have a material adverse effect on our business and operations. In addition, dividends to shareholders may be eliminated, as repayment of debt under the credit facility, senior notes and term loan has priority over dividend payments to our shareholders.

Cyber Security Risks

We are subject to a variety of information technology and system risks as part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach and destruction or interruption of our information technology systems by third parties or insiders. Additionally, use of personal devices can create further avenues for potential cyber-related incidents, as we have little or no control over the safety of these devices. Information technology and cyber risks have increased since the COVID-19 pandemic, with cybercriminals taking advantage of remote working environments working environments to increase malicious activities creating more threats for cyberattacks including phishing emails, malware-embedded mobile apps that purport to track infection rates, and targeting of vulnerabilities in remote access platforms. Although we have security measures and controls in place that are designed to mitigate these risks, the growing use of the digital space could increase technopolitical risks (example, by monitoring/intercepting phones and communications, or surveilling or locating persons of interest) further increasing the risk of a breach of our security , which could result in business interruptions, service disruptions, financial loss, theft of intellectual property and confidential information, litigation, enhanced regulatory attention and penalties, as well as reputational damage. Furthermore, the adoption of emerging technologies, such as cloud computing, artificial intelligence and robotics, call for continued focus and investment to manage risks effectively. Not managing this risk effectively may have an adverse effect and, therefore, may increase the risk of financial or reputational loss. The significance of any such event is difficult to quantify, but may be material in certain circumstances and could have a material effect on our business, financial condition and results of operations.

Ability to Divest Properties

Regulatory changes in Alberta and Saskatchewan have increased the minimum corporate liability rating required of purchasers of crude oil and natural gas properties. As a result, the potential number of parties able to acquire our non-core assets has been reduced, we may not be able to obtain full value for such assets, or transactions may involve greater risk and complexity. The Supreme Court of Canada’s decision in the Redwater Energy Corporation case may also impact our ability to transfer licenses, approvals or permits, and may result in increased costs and delays or require changes to our abandonment of projects and transactions. We also understand that further regulatory changes are being planned in Alberta and British Columbia, which may result in additional factors being considered when evaluating such transactions.

Title Defects or Litigation

Unforeseen title defects or litigation may result in a loss of entitlement to production, reserves and resources.

Although we conduct title reviews prior to the purchase of assets these reviews do not guarantee that an unforeseen defect in the chain of title will not arise. We maintain good working relationships with our industry partners; however, disputes may arise from time to time with respect to ownership of rights of certain properties or resources.

Foreign Currency Exposure

Beginning with the year ended December 31, 2021, we elected to change our reporting currency from Canadian dollars to U.S. dollars since the majority of our crude oil and natural gas properties are located in the U.S. Transactions denominated in foreign currencies are translated to the functional currency of the entity (Canadian dollars for Canadian entities and U.S. dollars for U.S. entities) using the exchange rate prevailing at the date of the transaction and, in the case of Canadian entities, then translated to U.S. dollars for reporting purposes. As a result, transactions in Canadian entities are affected by the exchange rate between the U.S. and Canadian dollar, including U.S. dollar denominated debt held in our Canadian parent, Canadian denominated receipts and payments and Canadian dollar dividend payments.

Enerplus is exposed to foreign exchange risk as it relates to Canadian and U.S. dollar. As Enerplus Corporation, as the parent company, has a Canadian functional currency, activity in the Canadian parent company that is transacted in U.S. dollars will result in realized and unrealized foreign exchange gains and losses that will be recorded on the Consolidated Statements of Income/(Loss). Further, we are exposed to foreign exchange risk in relation to our Canadian operations, Canadian G&A, Canadian dollar denominated cash deposits, dividends and working capital. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At December 31, 2021, we did not have any foreign exchange derivatives outstanding.

We continue to monitor fluctuations in foreign exchange and the impact on our operations.

Interest Rate Exposure

Movements in interest rates and credit markets may affect our borrowing costs and value of investments such as our shares as well as other equity investments.

Enerplus' senior notes bear interest at fixed rates while the term loan and Bank Credit Facility bear interest at floating rates. At December 31, 2021, approximately 43% of Enerplus' debt was based on fixed interest rates and 57% on floating interest rates (December 31, 2020 – 100% fixed), with weighted average interest rates of 4.2% and 1.9%, respectively (December 31, 2020 – 4.4%). At December 31, 2021 and 2020, Enerplus did not have any interest rate derivatives outstanding.

ADJUSTED FUNDS FLOW[1] SENSITIVITY

The sensitivities below reflect all of Enerplus' commodity contracts listed in Note 17 to the Financial Statements and are based on 2022 guidance production and price levels of: WTI - $75.00/bbl, NYMEX - $4.00/Mcf and a CDN/US exchange rate of 0.79. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table	Estimated Effect on 2022 Adjusted Funds Flow per Share(1)	
Increase of $5.00 per barrel in the price of WTI crude oil	$	0.26
Decrease of $5.00 per barrel in the price of WTI crude oil	$	(0.21)
Increase of $0.50 per Mcf in the price of NYMEX natural gas	$	0.13
Decrease of $0.50 per Mcf in the price of NYMEX natural gas	$	(0.12)
Change of 1,000 BOE/day in production	$	0.06
Change of $0.01 in the CDN/US exchange rate	$	—
Change of 1% in interest rate(2)	$	(0.01)

(1) Calculated using 242.1 million shares outstanding at February 23, 2021.
(2) The interest rate sensitivity reflects that all outstanding senior notes are based on fixed interest rates and are therefore excluded from this calculation.

2022 GUIDANCE(1)

Summary of 2022 Annual Expectations	Target
Capital spending ($ millions)	$370 - $430
Average annual production (BOE/day)	95,500 - 100,500
Average annual crude oil and natural gas liquids production (bbls/day)	58,000 - 62,000
Average production tax rate (% of net sales, before transportation)	7%
Operating expenses (per BOE)	$9.50 - $10.50
Transportation costs (per BOE)	$4.15
Cash G&A expenses (per BOE)	$1.25
Current tax expense ($ millions)	$10

2022 Differential/Basis Outlook(3)	Target
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	$(0.50)/bbl
Average Marcellus natural gas differential (compared to NYMEX natural gas)	$(0.75)/Mcf

(1) Guidance is based on the continued operation of DAPL and has not been adjusted to reflect the potential divestment of our Canadian assets as announced on February 2, 2022.
(2) This financial measure, including related guidance, as applicable, is a non-GAAP financial measure. See "Non-GAAP and Other Financial Measures" section in this MD&A.
(3) Excludes transportation costs

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

SUPPLEMENTARY

2021 Guidance and Results - Canadian Dollars and Company Interest Production

The following table outlines Enerplus' updated 2021 guidance and 2021 actual results presented in CDN dollars and company interest production volumes.

Summary of Guidance and Results	Revised 2021 Guidance	2021 Results
Capital spending ($ millions)	CDN$380	CDN$378
Average annual production (BOE/day)	113,750 - 114,750	114,748
Average annual crude oil and natural gas liquids production (bbls/day)	69,750 - 70,750	70,182
Fourth quarter average production (BOE/day)	124,500 - 128,500	128,023
Fourth quarter average crude oil and natural gas liquids production (bbls/day)	80,000 - 83,000	81,033
Average royalty rate (% of gross sales, before production tax and transportation)	26%	26%
Operating expenses (per BOE)	CDN$8.80	CDN$8.74
Transportation costs (per BOE)	CDN$3.85	CDN$3.84
Cash G&A expenses (per BOE)	CDN$1.15	CDN$1.15
Current tax expense ($ millions)	US$3	US$3

Differential/Basis Outlook and Results(1)		
Average U.S. Bakken crude oil differential (compared to WTI crude oil)	$(2.00)/bbl	$(1.97)/bbl
Average Marcellus natural gas differential (compared to NYMEX natural gas)	$(0.55)/Mcf	$(0.81)/Mcf

(1) Excludes transportation costs

NON-GAAP AND OTHER FINANCIAL MEASURES

Non-GAAP Financial Measures

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

These non-GAAP financial measures and non-GAAP ratios do not have standardized meanings or definitions as prescribed by U.S. GAAP and may not be comparable with the calculation of similar financial measures by other entities. For each measure, we have indicated the composition of the measure, identified the GAAP equivalency to the extent one exists, provided comparative detail where appropriate, indicated the reconciliation of the measure to the mostly directly comparable GAAP financial measure and provided details on the usefulness of the measure for the reader. These non-GAAP financial measures and non-GAAP ratios should not be considered as a substitute for, or superior to, measures of financial performance prepared in accordance with GAAP.

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

	Year ended December 31,		
($ millions)	2021	2020	2019
Cash flow from/(used in) operating activities	**$ 604.8**	**$ 335.9**	**$ 519.8**
Asset retirement obligation settlements	13.0	13.3	12.6
Changes in non-cash operating working capital	94.6	(83.7)	3.2
Adjusted funds flow	**$ 712.4**	**$ 265.5**	**$ 535.6**

"Adjusted net income" is used by Enerplus and is useful to investors and securities analysts in evaluating the financial performance of the company by adjusting for certain unrealized items and other items that the company considers appropriate to adjust given their irregular nature. The most directly comparable GAAP measure is net income/(loss). The calculation follows:

	Year ended December 31,		
($ millions)	2021	2020	2019
Net income/(loss)	**$ 234.4**	**$ (693.4)**	**$ (204.4)**
Unrealized derivative instrument (gain)/loss	109.5	18.1	59.7
Asset impairment	3.4	751.7	—
Unrealized foreign exchange (gain)/loss	(8.1)	1.4	(21.9)
Tax effect on above items	(24.9)	(201.0)	(13.5)
Other income related to investing activities	(4.6)	—	—
Goodwill impairment	—	149.2	347.3
Income tax rate adjustment on deferred taxes	6.0	—	17.1
Valuation allowance on deferred taxes	—	(11.5)	—
Adjusted net income	**$ 315.7**	**$ 14.5**	**$ 184.3**

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

	Year ended December 31,		
($ millions)	2021	2020	2019
Adjusted funds flow	$ 712.4	$ 265.5	$ 535.6
Capital spending	(302.3)	(217.2)	(465.9)
Free cash flow	**$ 410.1**	**$ 48.3**	**$ 69.7**

“Net debt” is calculated as current and long-term debt associated with senior notes plus any outstanding Bank Credit Facility and term loan balances, minus cash and cash equivalents. The calculation follows:

	Year ended December 31,	
($ millions)	2021	2020
Current portion of long-term debt	$ 100.6	$ 81.6
Long-term debt	601.2	303.8
Less: Cash and cash-equivalents	(61.4)	(89.9)
Net debt	**$ 640.4**	**$ 295.5**

“Net debt to adjusted funds flow ratio” is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The net debt to adjusted funds flow ratio is calculated as net debt divided by a trailing twelve months of adjusted funds flow. There is no directly comparable GAAP equivalent for this measure, and it is not equivalent to any of our debt covenants. The calculation follows:

	Year ended December 31,	
($ millions)	2021	2020
Net debt	$ 640.4	295.5
Adjusted funds flow	712.4	265.5
Net debt to adjusted funds flow ratio	**0.9x**	**1.1x**

“Netback before impact of commodity derivative contracts” and **“Netback after impact of commodity derivative contracts”** is used by Enerplus and is useful to investors and securities analysts, in evaluating operating performance of our crude oil and natural gas assets, both before and after consideration of our realized gain/(loss) on commodity derivative instruments. A direct GAAP equivalent does not exist for these measures, although a reconciliation is provided as follows:

	Year ended December 31,		
($ millions)	2021	2020	2019
Crude oil and natural gas sales	$ 1,482.6	$ 553.7	$ 945.9
Less:			
Operating expenses	(292.4)	(197.1)	(219.3)
Transportation costs	(128.3)	(98.7)	(109.2)
Production taxes	(102.0)	(37.4)	(62.7)
Netback before impact of commodity derivative contracts	**$ 959.9**	**$ 220.5**	**$ 554.7**
Net realized gain/(loss) on derivative instruments	(163.0)	92.9	11.6
Netback after impact of commodity derivative contracts	**$ 796.9**	**$ 313.4**	**$ 566.3**

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

	Year ended December 31,		
($ millions)	2021	2020	2019
Capital spending	$ 302.3	$ 217.2	$ 465.9
Adjusted funds flow	712.4	265.5	535.6
Reinvestment rate (%)	**42%**	**82%**	**87%**

“Working Capital Deficiency” is used by Enerplus to understand future liquidity. A direct GAAP equivalent does not exist for this measure. A reconciliation is provided as follows:

	Year ended December 31,	
($ millions)	2021	2020
Working capital	$ (315.5)	(125.0)
Less: Cash and cash-equivalents	(61.3)	(89.9)
Less: Current portion of derivative financial assets and liabilities	137.5	12.3
Working capital deficiency	**$ (239.3)**	**$ (202.6)**

Other Financial Measures

SUPPLEMENTARY FINANCIAL MEASURES

Supplementary financial measures are financial measures disclosed by a company that (a) are, or are intended to be, disclosed on a periodic basis to depict the historical or expected future financial performance, financial position or cash flow of a company, (b) are not disclosed in the financial statements of the company, (c) are not non-GAAP financial measures, and (d) are not non-GAAP ratios. The following section provides an explanation of the composition of those supplementary financial measures if not previously provided:

"Capital spending" Capital and office expenditures, excluding other capital assets/office capital and property and land acquisitions and divestments.

"Cash general and administrative expenses" or "Cash G&A expenses" General and administrative expenses that are settled through cash payout, as opposed to expenses that relate to accretion or other non-cash allocations that are recorded as part of general and administrative expenses.

"Cash share-based compensation" or "Cash SBC expenses" Share-based compensation that is settled by way of cash payout, as opposed to equity settled.

INTERNAL CONTROLS AND PROCEDURES

Internal Controls over Financial Reporting

We maintain internal controls over financial reporting that are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with U.S. GAAP. Management is responsible for establishing and maintaining adequate internal controls over financial reporting, as defined in Rule 13a – 15(f) and 15d – 15(f) under the U.S. Securities Exchange Act of 1934, as amended (the Exchange Act) and under National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings (NI 51-109). Management, including the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of Enerplus Corporation, have conducted an evaluation of our internal control over financial reporting based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO 2013). Based on management's assessment as of December 31, 2021, management has concluded that our internal controls over financial reporting are effective.

The effectiveness of internal controls over financial reporting as of December 31, 2021 was audited by KPMG LLP, an independent registered public accounting firm, as stated in their Report of Independent Registered Public Accounting Firm, which is included with the annual financial statements.

Due to inherent limitations, internal controls over financial reporting are not intended to provide absolute assurance that a misstatement of our financial statements would be prevented or detected. Further, the evaluation of the effectiveness of internal control over financial reporting was made as of a specific date, and continued effectiveness in future periods is subject to the risks that controls may become inadequate.

Changes in Internal Controls over Financial Reporting

There were no changes in our internal control over financial reporting in 2021 that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Disclosure Controls and Procedures

We maintain disclosure controls and procedures designed to provide reasonable assurance that information required to be disclosed in our interim and annual filings is reviewed, recognized and disclosed accurately and in the appropriate time period. Management, including the CEO and CFO, carried out an evaluation, as of December 31, 2021, of the effectiveness of the design and operation of disclosure controls and procedures of Enerplus, as defined in Rule 13a – 15(e) and 15d – 15(e) under the Exchange Act and NI 52-109. Based on that evaluation, the CEO and CFO have concluded that the design and operation of disclosure controls and procedures at Enerplus were effective to ensure that information required to be disclosed in the reports we file or submit under the Exchange Act or Canadian securities legislation is recorded, processed, summarized and reported within the time periods specified in the rules and forms therein.

It should be noted that while the CEO and CFO believe that our disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that these disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current 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.

PRESENTATION OF RESERVES INFORMATION

All of Enerplus' reserves have been evaluated in accordance with Canadian reserve evaluation standards under National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("Canadian NI 51-101 Standards"). Independent reserves evaluations have been conducted on properties comprising approximately 98% of the net present value (discounted at 10%, before tax, using January 1, 2022 forecast prices and costs) of Enerplus' total proved plus probable reserves. McDaniel, an independent petroleum consulting firm based in Calgary, Alberta, has evaluated properties which comprise approximately 71% of the net present value (discounted at 10%, before tax, using the average commodity price forecasts and inflation rates of McDaniel, GLJ Ltd. ("GLJ") and Sproule Associates Limited ("Sproule") as of January 1, 2022) of Enerplus' proved plus probable reserves located in Canada and all of the reserves associated with the Enerplus' properties located in North Dakota and Colorado. Enerplus has evaluated the remaining 29% of the net present value of its Canadian properties using similar evaluation parameters, including the same forecast price and inflation rate assumptions utilized by McDaniel. McDaniel has reviewed Enerplus' internal evaluation of these properties. NSAI, independent petroleum consultants based in Dallas, Texas, has evaluated all of Enerplus' reserves associated with Enerplus' properties in Pennsylvania in accordance with Canadian NI 51-101 Standards. For consistency in the Enerplus' reserves reporting, NSAI also used the average commodity price forecasts and inflation rates of McDaniel, GLJ and Sproule as of January 1, 2022 to prepare its report.

Enerplus has also presented certain reserves information effective December 31, 2021 in accordance with the provisions of the Financial Accounting Standards Board's ASC Topic 932 Extractive Activities – Oil and Gas, which generally utilize definitions and estimations of proved reserves that are consistent with Rule 4-10 of Regulation S-X promulgated by the SEC, but does not necessarily include all of the disclosure required by the SEC disclosure standards set forth in Subpart 1200 of Regulation S-K (the "U.S. Standards"). Concurrent to the evaluation of Enerplus' Canadian NI 51-101 Standards reserves, McDaniel and NSAI prepared and reviewed estimates of Enerplus' reserves under the U.S. Standards. The practice of preparing production and reserves data under Canadian NI 51-101 Standards differs from the U.S. Standards. The primary differences between the two reporting requirements include:

- *the Canadian NI 51-101 Standards require disclosure of proved and probable reserves, while the U.S. Standards require disclosure of only proved reserves;*
- *the Canadian NI 51-101 Standards require the use of forecast prices in the estimation of reserves, while the U.S. Standards require the use of 12-month average trailing historical prices, which are held constant;*
- *the Canadian NI 51-101 Standards require disclosure of reserves on a gross (before royalties) and net (after royalties) basis, while the U.S. Standards require disclosure on a net (after royalties) basis;*
- *the Canadian NI 51-101 Standards require disclosure of production on a gross (before royalties) basis, while the U.S. Standards require disclosure on a net (after royalties) basis;*
- *the Canadian NI 51-101 Standards require that reserves and other data be reported on a more granular product type basis than required by the U.S. Standards; and*
- *the Canadian NI 51-101 Standards require that proved undeveloped reserves be reviewed annually for retention or reclassification if development has not proceeded as previously planned, while the U.S. Standards specify a five-year limit after initial booking for the development of proved undeveloped reserves.*

FD&A costs presented in this MD&A are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year. FD&A costs are presented in U.S. dollars per net or gross BOE as specified.

Complete disclosure of our oil and gas reserves and other oil and gas information presented in accordance with Canadian NI 51-101 Standards, as well as supplemental information presented in accordance with U.S. Standards, is contained within our AIF, which is available on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, our AIF forms part of our Form 40-F that is filed with the U.S. Securities and Exchange Commission and is available on EDGAR at www.sec.gov.

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: the continued uncertainty regarding timing and impact of COVID-19, expected 2022 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the 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 our commodity risk management program in 2022 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash G&A, share-based compensation and financing expenses; operating, transportation and tax expenses; expected free cash flow generation and use thereof, including to fund share repurchases and dividends; capital spending levels in 2022 and impact thereof on our production levels and land holdings; potential future asset impairments, as well as relevant factors that may affect such impairments; the amount and timing of our future abandonment and reclamation costs and asset retirement obligations and the source of funds necessary in order to pay such obligations; our ESG initiatives, including GHG emissions intensity, freshwater use reduction and health and safety targets for 2022; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our Bank Credit Facility and outstanding senior notes; our future acquisitions and dispositions, including the divestment process for our Canadian assets in 2022 and the completion and timing thereof and use of proceeds and anticipated benefits therefrom; the impact of the Sleeping Giant/Russian Creek Divestment on Enerplus' operations, reserves, inventory and opportunities, financial condition and overall strategy; and the amount of future cash dividends that we may pay to our shareholders and the source of funds necessary in order to pay such dividends.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated, including the continued operation of DAPL; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices beyond our current expectations; current commodity prices, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our adjusted funds flow and availability under our Bank Credit Facility to fund our working capital deficiency; the availability of third party services; the extent of our liabilities; and the availability of technology and process to achieve environmental targets. In addition, our 2022 guidance contained in this MD&A is based on the following: a WTI price of $75.00/bbl, a NYMEX price of $4.00/Mcf, a Bakken crude oil price differential of $(0.50)/bbl below WTI, a Marcellus natural gas price differential of $(0.75)/Mcf below NYMEX and a CDN/US exchange rate of 0.79. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

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: decreases in commodity prices or volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; 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 and increased capital and operating costs resulting therefrom; inability to comply with applicable environmental government regulations or regulatory approvals and resulting compliance and enforcement actions; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our Bank Credit Facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors, reliance on industry partners and third party service providers; failure to realize the anticipated benefits of the Sleeping Giant/Russian Creek Divestment; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks identified in our AIF and Form 40-F as at December 31, 2021).

The purpose of our adjusted funds flow sensitivity is to assist readers in understanding our expected and targeted financial results, and this information may not be appropriate for other purposes. The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2021, our internal control over financial reporting is effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2021, has been audited by KPMG LLP, the Independent Registered Public Accounting Firm, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2021.

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 24, 2022

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation:

Opinion on Internal Control Over Financial Reporting

We have audited Enerplus Corporation's and subsidiaries (the Company) internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2021 and 2020, the related consolidated statements of income/(loss) and comprehensive income/(loss), changes in shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2021, and the related notes (collectively, the consolidated financial statements), and our report dated February 24, 2022 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP
Chartered Professional Accountants
Calgary, Canada
February 24, 2022

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with accounting principles generally accepted in the United States of America. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 24, 2022. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

To meet its responsibility for reliable and accurate financial statements, management has established and monitors systems of internal control which are designed to provide reasonable assurance that financial information is relevant, reliable and accurate, and that assets are safeguarded and transactions are executed in accordance with management's authorization.

The consolidated financial statements have been examined by KPMG LLP, Independent Registered Public Accountants. Their responsibility is to express a professional opinion on the fair presentation of the consolidated financial statements in accordance with accounting principles generally accepted in the United States of America. The Report of Independent Registered Public Accounting Firm outlines the scope of their examination and sets forth their opinion.

The Audit Committee, consisting exclusively of independent directors, has reviewed these statements with management and the Independent Registered Public Accounting Firm and has recommended their approval to the Board of Directors. The Board of Directors has approved the consolidated financial statements of the Company.

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 24, 2022

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Enerplus Corporation and subsidiaries (the Company) as of December 31, 2021 and 2020, the related consolidated statements of income/(loss) and comprehensive income/(loss), changes in shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2021, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2021, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 24, 2022 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Change in Reporting Currency

As discussed in Note 2(a)(i) to the consolidated financial statements, the Company has elected to change its reporting currency from Canadian dollars to U.S. dollars. The change in reporting currency has been applied retrospectively in the consolidated financial statements.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Impact of estimated proved oil and gas reserves on the calculations of depletion expense and the ceiling test related to United States of America ("US") oil and gas properties

As discussed in Note 2(d) to the consolidated financial statements, the Company depletes its oil and gas properties each quarter using the unit-of-production method on a country-by-country basis. Under such method, capitalized costs for the US oil and gas properties are depleted over the estimated proved oil and gas reserves ("country proved reserves"). For the year ended December 31, 2021, the Company recorded depletion, depreciation and accretion expense of $271 million, a portion of which related to depletion expense on the US oil and gas properties. Additionally, as discussed in Note 2(d) to the consolidated financial statements, the Company is required to perform a quarterly ceiling test calculation on a country-by-country basis. For the year ended December 31, 2021, the Company recorded no ceiling test impairments related to the US oil and gas properties. The Company limits the capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and the related deferred income tax effects, by country, to the estimated future net cash flows from country proved reserves discounted at 10 percent, net of related tax effects, plus the lower of cost or fair value of unproved oil and gas properties. The estimation of country proved reserves, which are used in the calculations of depletion and the ceiling test, requires the expertise of independent reservoir engineering specialists, who take into consideration assumptions related to forecasted production and forecasted operating and capital costs. The estimated future net cash flows are calculated using the simple average of the preceding twelve months' first-day-of-the-month commodity prices. The Company engages independent reservoir engineering specialists to estimate country proved reserves.

We identified the impact of estimated country proved reserves on the calculations of depletion expense and the ceiling test related to US oil and gas properties as a critical audit matter. Changes in reserve assumptions related to forecasted production and forecasted operating and capital costs could have had a significant impact on the calculations of depletion expense and the ceiling tests. A high degree of auditor judgment was required in evaluating the country proved reserves, and assumptions related to forecasted production and forecasted operating and capital costs, which were an input to the calculations of depletion expense and the ceiling test.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to:

- the calculations of depletion expense and the ceiling test, and
- the estimation of the country proved reserves and the assumptions related to forecasted production and forecasted operating and capital costs.

We assessed the calculations of depletion expense and the ceiling test for compliance with regulatory standards. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who estimated the country proved reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate country proved reserves for compliance with regulatory standards. We compared the Company's 2021 actual production and operating and capital costs by country to those estimates used in the prior year estimate of country proved reserves to assess the Company's ability to accurately forecast. We assessed the estimates of forecasted production and forecasted operating and capital cost assumptions used in the country proved reserves by comparing them to historical results.

Fair value measurement of property, plant and equipment in business combination

As discussed in Note 3(a) to the consolidated financial statements, the Company acquired Bruin E&P Holdco, LLC ("Bruin") in a business combination that was completed on March 10, 2021 ("acquisition date"). As a result of the transaction, the Company acquired property, plant and equipment ("PP&E") with an acquisition-date fair value $542 million. The determination of the acquisition-date fair value of PP&E involves significant estimates, including the cash flows associated with the proved and probable oil and gas reserves acquired (the "Bruin reserves") and the discount rate. The estimation of Bruin reserves, which are used in the calculation of the acquisition-date fair value of PP&E, requires the expertise of independent reservoir engineering specialists, who take into consideration assumptions related to forecasted production, forecasted operating and capital costs and forecasted oil and gas prices ("reserve assumptions"). The Company engages independent reservoir engineering specialists to estimate the Bruin reserves.

We identified the determination of the acquisition-date fair value of PP&E acquired in the Bruin transaction as a critical audit matter. Changes in reserve assumptions and the discount rate could have had a significant impact on the determination of the acquisition-date fair value of PP&E. A high degree of auditor judgment was required in evaluating the reserve assumptions associated with the Bruin reserves and the discount rates. Additionally, the evaluation of this estimate required specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's determination of the acquisition-date fair value of PP&E, including controls related to:

- the development of the discount rate, and
- the estimation of future cash flows associated with the Bruin reserves including the related reserve assumptions.

We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who estimated the Bruin reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate the Bruin reserves for compliance with regulatory standards. We assessed the forecasted commodity prices used in the Bruin reserve by comparing them to those published by other reserve engineering firms. We assessed the estimates of forecasted production and forecasted operating cost assumptions used in the Bruin reserves by comparing them to 2020 results. We assessed the forecasted capital cost assumptions used in the Bruin reserves by comparing them to the 2021 results. We involved a valuation professional with specialized skills and knowledge, who assisted in:

- evaluating the Company's determination of the discount rate by comparing the inputs to the discount rate to publicly available market data for comparable entities and assessed the resulting discount rate; and
- evaluating the Company's estimate of the acquisition-date fair value of PP&E by comparing it to publicly available market data and valuation metrics for comparable entities or asset transactions.

/s/ KPMG LLP

Chartered Professional Accountants

We have served as the Company's auditor since 2017.

Calgary, Canada
February 24, 2022

Consolidated Balance Sheets

(US$ thousands)	Note	December 31, 2021	December 31, 2020
Assets			
Current assets			
Cash and cash equivalents		$ 61,348	$ 89,945
Accounts receivable	4	227,988	83,596
Other current assets		10,956	5,609
Derivative financial assets	17	5,668	2,790
		305,960	181,940
Property, plant and equipment:			
Crude oil and natural gas properties (full cost method)	5, 6	1,253,505	452,302
Other capital assets	5	13,887	11,499
Property, plant and equipment		1,267,392	463,801
Other long-term assets	7	9,756	3,845
Right-of-use assets	11	26,118	25,818
Deferred income tax asset	15	380,858	477,014
Total Assets		$ 1,990,084	$ 1,152,418
Liabilities			
Current liabilities			
Accounts payable	8	$ 367,008	$ 197,895
Dividends payable		—	1,749
Current portion of long-term debt	9	100,600	81,600
Derivative financial liabilities	17	143,200	15,136
Current portion of lease liabilities	11	10,618	10,523
		621,426	306,903
Long-term debt	9	601,171	303,800
Asset retirement obligation	10	132,814	102,325
Derivative financial liabilities	17	7,098	—
Lease liabilities	11	18,265	18,425
		759,348	424,550
Total Liabilities		1,380,774	731,453
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: December 31, 2021 – 244 million shares			
December 31, 2020 – 223 million shares	16	3,094,061	3,113,829
Paid-in capital		50,881	49,382
Accumulated deficit		(2,238,325)	(2,447,735)
Accumulated other comprehensive loss		(297,307)	(294,511)
		609,310	420,965
Total Liabilities & Shareholders' Equity		$ 1,990,084	$ 1,152,418
Commitments and Contingencies	18		
Subsequent Events	9, 16, 21		

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

Approved on behalf of the Board of Directors:

/s/ Hilary Foulkes
Director

/s/ Jeffrey Sheets
Director

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

For the year ended December 31 (US$ thousands)	**Note**	**2021**	**2020**	**2019**
Revenues				
Crude oil and natural gas sales	12	$ 1,482,575	$ 553,739	$ 945,894
Commodity derivative instruments gain/(loss)	17	(274,432)	75,742	(47,930)
		1,208,143	629,481	897,964
Expenses				
Operating		292,433	197,097	219,343
Transportation		128,309	98,681	109,241
Production taxes		101,953	37,417	62,662
General and administrative	13	56,807	43,097	54,920
Depletion, depreciation and accretion		271,336	218,118	269,046
Asset impairment	6	3,420	751,723	—
Goodwill impairment	6	—	149,217	347,283
Interest		27,395	20,737	25,580
Foreign exchange (gain)/loss	14	(6,908)	1,232	(16,420)
Transaction costs and other expense/(income)		(2,487)	4,489	(5,695)
		872,258	1,521,808	1,065,960
Income/(Loss) Before Taxes		335,885	(892,327)	(167,996)
Current income tax expense/(recovery)	15	2,689	(10,716)	(25,246)
Deferred income tax expense/(recovery)	15	98,755	(188,260)	61,650
Net Income/(Loss)		$ 234,441	$ (693,351)	$ (204,400)
Other Comprehensive Income/(Loss)				
Unrealized gain/(loss) on foreign currency translation		(6,893)	(2,169)	11,995
Foreign exchange gain/(loss) on net investment hedge, net of tax	17	4,097	1,780	—
Total Comprehensive Income/(Loss)		$ 231,645	$ (693,740)	$ (192,405)
Net Income/(Loss) per Share				
Basic	16	$ 0.93	$ (3.12)	$ (0.88)
Diluted	16	$ 0.90	$ (3.12)	$ (0.88)

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

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (US$ thousands)		**2021**		**2020**		**2019**
Share Capital						
Balance, beginning of year	$	3,113,829	$	3,106,875	$	3,294,496
Issue of shares (net of tax effected issue costs)		99,516		—		—
Purchase of common shares under Normal Course Issuer Bid		(128,686)		(3,582)		(190,917)
Share-based compensation – treasury settled		9,402		10,694		3,296
Cancellation of predecessor shares		—		(158)		—
Balance, end of year	$	3,094,061	$	3,113,829	$	3,106,875
Paid-in Capital						
Balance, beginning of year	$	49,382	$	56,439	$	46,626
Share-based compensation – tax withholdings settled in cash		(3,551)		(5,567)		(3,705)
Share-based compensation – treasury settled		(9,402)		(10,694)		(3,296)
Share-based compensation – non-cash		14,452		9,204		16,814
Balance, end of year	$	50,881	$	49,382	$	56,439
Accumulated Deficit						
Balance, beginning of year	$	(2,447,735)	$	(1,736,355)	$	(1,567,680)
Purchase of common shares under Normal Course Issuer Bid		5,504		1,775		56,632
Cancellation of predecessor shares		—		158		—
Net income/(loss)		234,441		(693,351)		(204,400)
Dividends declared[1]		(30,535)		(19,962)		(20,907)
Balance, end of year	$	(2,238,325)	$	(2,447,735)	$	(1,736,355)
Accumulated Other Comprehensive Income/(Loss)						
Balance, beginning of year	$	(294,511)	$	(294,122)	$	(306,117)
Unrealized gain/(loss) on foreign currency translation		(6,893)		(2,169)		11,995
Foreign exchange gain/(loss) on net investment hedge, net of tax		4,097		1,780		—
Balance, end of year	$	(297,307)	$	(294,511)	$	(294,122)
Total Shareholders' Equity	$	609,310	$	420,965	$	1,132,837

(1) For the year ended December 31, 2021, dividends declared were CDN$0.15 ($0.12) per share (2020 – CDN$0.12 ($0.09) per share; 2019 – CDN$0.12 ($0.09) per share).

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

Consolidated Statements of Cash Flows

For the year ended December 31 (US$ thousands)	**Note**	**2021**	**2020**	**2019**
Operating Activities				
Net income/(loss)		$ 234,441	$ (693,351)	$ (204,400)
Non-cash items add/(deduct):				
Depletion, depreciation and accretion		271,336	218,118	269,046
Asset impairment	6	3,420	751,723	—
Goodwill impairment	6	—	149,217	347,283
Changes in fair value of derivative instruments	17	109,536	18,074	59,750
Deferred income tax expense/(recovery)	15	98,755	(188,260)	61,650
Foreign exchange (gain)/loss on debt and working capital	14	(8,055)	1,363	(21,899)
Share-based compensation and general and administrative	13, 16	13,424	9,508	17,356
Other expense/(income)	10	(4,594)	—	—
Amortization of debt issuance costs	9	1,093	—	—
Translation of U.S. dollar cash held in parent company	14	(2,330)	(902)	6,825
Other income reclassified to Investing Activities	20	(4,593)	—	—
Asset retirement obligation settlements	10	(12,951)	(13,275)	(12,646)
Changes in non-cash operating working capital	20	(94,643)	83,669	(3,197)
Cash flow from/(used in) operating activities		604,839	335,884	519,768
Financing Activities				
Proceeds from bank term loan/bank credit facility	9	400,000	—	—
Debt issuance costs	9	(4,621)	—	—
Repayment of senior notes	9	(81,600)	(81,600)	(44,444)
Proceeds from the issuance of shares	16	98,339	—	—
Purchase of common shares under Normal Course Issuer Bid	16	(123,182)	(1,807)	(134,285)
Share-based compensation – tax withholdings settled in cash	16	(3,551)	(5,567)	(3,705)
Dividends	16, 20	(32,284)	(19,897)	(21,003)
Cash flow from/(used in) financing activities		253,101	(108,871)	(203,437)
Investing Activities				
Capital and office expenditures	20	(271,131)	(248,990)	(454,521)
Bruin acquisition	3	(420,249)	—	—
Dunn County acquisition	3	(305,076)	—	—
Property and land acquisitions	5	(9,846)	(7,491)	(18,409)
Property divestments	3, 5, 7	108,193	4,456	7,210
Other expense/(income)	20	4,593	—	—
Cash flow from/(used in) investing activities		(893,516)	(252,025)	(465,720)
Effect of exchange rate changes on cash and cash equivalents		6,979	(1,786)	(295)
Change in cash and cash equivalents		(28,597)	(26,798)	(149,684)
Cash and cash equivalents, beginning of year		89,945	116,743	266,427
Cash and cash equivalents, end of year		$ 61,348	$ 89,945	$ 116,743

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

Notes to Consolidated Financial Statements

1) REPORTING ENTITY

These annual audited Consolidated Financial Statements ("Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation (the "Company" or "Enerplus") including its Canadian and United States ("U.S.") subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' corporate offices are located in Calgary, Alberta, Canada and Denver, Colorado, United States.

2) SIGNIFICANT ACCOUNTING POLICIES

The following significant accounting policies are presented to assist the reader in evaluating these Consolidated Financial Statements and, together with the following notes, are an integral part of the Consolidated Financial Statements.

a) Basis of Preparation

Enerplus' Consolidated Financial Statements have been prepared by management in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP"). Certain prior period amounts have been restated to conform with current period presentation.

i. Reporting and Functional Currency

In the fourth quarter of 2021, the Company elected to change its reporting currency from Canadian dollars to U.S. dollars since the majority of its crude oil and natural gas properties are located in the U.S., and to facilitate a more direct comparison to other U.S. exploration and development companies. The change in reporting currency is a voluntary change which is accounted for retrospectively. All prior periods have been restated to U.S. dollars using the procedures outlined below:

- Consolidated Statements of Income/(Loss) and Consolidated Statements of Cash Flows have been translated into U.S. dollars using average foreign exchange rates for the relevant period.
- Assets and liabilities in the Consolidated Balance Sheets have been translated into U.S. dollars at the closing foreign exchange rates on the respective balance sheet dates.
- The shareholders' equity section of the Consolidated Balance Sheets has been translated into U.S. dollars using historical foreign exchange rates.
- Earnings per share disclosures have also been restated to U.S. dollars to reflect the change in reporting currency. Dividends are disclosed in Canadian dollars with the U.S. dollar equivalent disclosed in parentheses as dividends were declared in Canadian dollars.

The functional currency of the parent entity has been and continues to be Canadian dollars and the functional currency of the U.S. subsidiaries continues to be U.S. dollars. All references to $ or US$ are to U.S. dollars and references to CDN$ are to Canadian dollars. All financial information presented in U.S. and Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

ii. Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Actual results could differ from these estimates, and changes in estimates are recorded when known. Significant estimates made by management include those that relate to: crude oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment of property, plant and equipment, asset retirement obligations, income taxes, ability to realize deferred income tax assets, impairment assessments of goodwill and the fair value of derivative instruments. The estimation of crude oil and natural gas reserves and the related present value of future cash flows involves the use of independent reservoir engineering specialists and numerous estimates and assumptions including forecasted production volumes, forecasted operating, royalty and capital cost assumptions and assumptions around commodity pricing. Inflation and discount rates impacting various items within the Company's financial statements are also subject to management estimation. When estimating the present value of future cash flows, the discount rate implicitly considers the potential impacts, if any, due to climate change factors. Enerplus uses the most current information available and exercises judgment in making estimates and assumptions. In the opinion of management, these Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

iii. Basis of Consolidation

These Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled crude oil and natural gas assets are accounted for following the concept of undivided interest, whereby Enerplus' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

iv. Business Combinations

The acquisition method of accounting is used to account for acquisitions that meet the definition of a business under U.S. GAAP. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values, with limited exceptions, at the acquisition date.

b) Revenue

Enerplus sells the majority of its production pursuant to variable-price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver a fixed or variable volume of crude oil, natural gas liquids or natural gas to the contract counterparty. Crude oil, natural gas and natural gas liquids are sold under contracts of varying terms, including multi-year contracts. Revenues are typically collected in the month following production.

Revenue from the sale of crude oil, natural gas and natural gas liquids is measured based on the consideration specified in contracts with customers, net of sales taxes. Enerplus recognizes revenue when it satisfies a performance obligation by transferring control of the product to a customer. This is generally at the time the customer obtains legal title to the product and when it is physically transferred to the contractual delivery points.

Enerplus evaluates its arrangements with third parties and partners to determine if the Company acts as the principal or as an agent. In making this evaluation, management considers if Enerplus retains control of the product being delivered to the end customer. As part of this assessment, management considers whether the Company retains the economic benefits associated with the good being delivered. Management also considers whether the Company has the primary responsibility for the delivery of the product, the ability to establish prices or the inventory risk, in which case the Company would be the principal and the revenue is recognized on a gross basis. Any associated fees are recorded as an expense. If Enerplus acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

All references to crude oil and natural gas revenue or production in the Consolidated Financial Statements are net of royalties.

c) Transportation

Enerplus generally sells crude oil and natural gas under two types of agreements which are common in industry. Both types of agreements include a transportation charge. One is a net-back arrangement, under which the Company sells crude oil or natural gas at the wellhead and collects a price, net of the transportation incurred by the purchaser. In this case, sales are recorded at the price received from the purchaser, net of transportation costs.

Under the other arrangement, Enerplus sells crude oil or natural gas at a specific delivery point, pays transportation to a third party and receives proceeds from the purchaser with no transportation deduction. In this case, transportation costs are recorded as transportation expense on the Consolidated Statements of Income/(Loss).

d) Crude Oil and Natural Gas Properties

Enerplus uses the full cost method of accounting for its crude oil and natural gas properties. Under this method, all acquisition, exploration and development costs incurred in finding crude oil and natural gas reserves are capitalized, including general and administrative costs attributable to these activities. These costs are recorded on a country-by-country cost centre basis as crude oil and natural gas properties subject to depletion ("full cost pool"). Costs associated with production and general corporate activities are expensed as incurred.

The net carrying value of both proved and unproved crude oil and natural gas properties is depleted using the unit of production method using proved reserves, as determined using a constant price assumption of the simple average of the preceding twelve months' first-day-of-the-month commodity prices ("SEC prices"). The depletion calculation takes into account estimated future development costs necessary to bring those reserves into production.

Under full cost accounting, a ceiling test is performed on a cost centre basis each quarter. Enerplus limits capitalized costs of proved and unproved crude oil and natural gas properties, net of accumulated depletion and the related deferred income tax effects, to the estimated future net cash flows from proved crude oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties ("the ceiling"). This discount rate is not adjusted for current market trends, changes in the cost of capital and the potential impacts, if any, on the discount rate due to climate change or any other factors, as it is prescribed under U.S. GAAP. The ultimate period in which global energy markets can fully transition from carbon-based sources to alternative energy is highly uncertain, and as such, it is difficult to determine the impact on estimated future net cash flows of such a transition.

The estimated future net cash flows are calculated using the simple average of the preceding twelve months' first-day-of-the-month commodity prices. If such capitalized costs exceed the ceiling, a write-down equal to that excess is recorded as a non-cash charge to net income. A write-down is not reversed in future periods even if higher crude oil and natural gas prices subsequently increase the ceiling.

Under certain circumstances, where the carrying value of the full cost centre exceeds the ceiling test limitation, the Company may seek a temporary waiver from the SEC to exclude certain amounts from the full cost ceiling limitation. The Company must demonstrate that the fair value of the excluded properties clearly exceeds the carrying value.

Under full cost accounting rules, divestments of crude oil and natural gas properties are generally accounted for as adjustments to capitalized costs, with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would have otherwise significantly altered the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss is recognized.

e) Other Capital Assets

Other capital assets are recorded at historical cost, net of depreciation, and include furniture, fixtures, leasehold improvements, and computer equipment. Depreciation is calculated on a straight-line basis over the estimated useful life of the respective asset. The cost of repairs and maintenance is expensed as incurred.

f) Other Long-term Assets

Other Long-term Assets include Company-owned line fill in third party pipelines and long-term receivables. Line fill is recorded at lower of cost and net realizable value.

g) Cash and Cash Equivalents

Cash and cash equivalents include cash and highly liquid investments with maturities of less than 90 days.

h) Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

Goodwill is assessed for impairment annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus first performs a qualitative assessment to determine whether events or changes in circumstances indicate that goodwill may be impaired. If it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to the reporting unit's fair value, with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). The loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. The estimated fair value of the reporting unit involves numerous estimates including the estimated cash flows from proved reserves (and in certain periods probable reserves) associated with the reporting unit and the appropriate discount rate to apply to the estimated cash flows. The discount rate is based on the estimated cost of capital.

i) Asset Retirement Obligations

Enerplus' crude oil and natural gas operating activities give rise to dismantling, decommissioning, reclamation, and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future asset retirement obligation liability at each balance sheet date. Upon recognition, the liability is recorded at its estimated fair value. The associated asset retirement cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability and related asset retirement cost can arise as a result of revisions in the estimated amount or timing of cash flows.

Depletion of asset retirement costs and increases in asset retirement obligations resulting from the passage of time are recorded to depreciation, depletion and accretion and charged against net income in the Consolidated Statements of Income/(Loss).

j) Leases

Enerplus determines if an arrangement is an operating or finance lease, as defined under U.S. GAAP, at inception. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. These leases are included in right-of-use ("ROU") assets and lease liabilities in the Consolidated Balance Sheet.

ROU assets represent the Company's right to use an underlying asset for the lease term and lease liabilities represent the obligation to make lease payments arising from such leases. Lease liabilities are recognized at the lease commencement date based on the present value of remaining lease payments over the lease term, taking into consideration conditions such as incentives and termination penalties, as appropriate. A corresponding ROU asset is recognized at the amount of the lease liability, adjusted for payments made prior to lease commencement or initial direct costs, if any.

When calculating the present value, Enerplus uses the rate implicit in the lease, or uses its incremental borrowing rate for a similar term and risk profile based on the information available at the commencement date. Enerplus' lease terms may have options to extend or terminate the lease which are included in the calculation of lease liabilities when it is reasonably certain that it will exercise those options. Lease expense for operating leases is recognized on a straight-line basis over the lease term.

Lease agreements can contain both lease and non-lease components, which are accounted for separately. For certain equipment leases, a portfolio approach is applied to account for the ROU assets and liabilities.

k) Income Tax

Enerplus uses the liability method of accounting for income taxes. Deferred income tax assets and liabilities are recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax assets are reviewed each period and a valuation allowance is provided if, after considering available evidence, it is more likely than not that a deferred tax asset will not be realized. Enerplus considers both positive and negative evidence including historic and expected future taxable income, reversing existing temporary differences and tax basis carry forward periods in making this assessment.

The expected future taxable income considered in the analysis of the valuation allowance is based on cash flows from the proven and probable reserves. The estimated cash flows from proven and probable reserves is subject to numerous estimates and judgments and involves the use of independent reserve evaluators. A valuation allowance is removed in any period where available evidence indicates all or a portion of the valuation allowance is no longer required. The financial statement effect of an uncertain tax position is recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. Penalties and interest expense related to income tax are recognized in income tax expense.

l) Financial Instruments

i. Fair Value Measurements

Financial instruments are initially recorded at fair value, defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. For financial instruments carried at fair value, and when disclosing the fair value of financial instruments on certain non-financial items, inputs used in determining the fair value are characterized according to the following fair value hierarchy:

- Level 1 – Inputs represent quoted market prices in active markets for identical assets or liabilities.
- Level 2 – Inputs other than quoted market prices included within Level 1 that are observable for the asset or liability, either directly or indirectly, such as quoted market prices for similar assets or liabilities in active markets or other market corroborated inputs.
- Level 3 – Inputs that are not observable from objective sources, such as forward prices supported by little or no market activity or internally developed estimates of future cash flows used in a present value model.

Subsequent measurement is based on classification of the financial instrument into one of the following five categories: held-for-trading, held-to-maturity, available-for-sale, loans and receivables or other financial liabilities.

ii. Non-derivative financial instruments

The carrying amount of cash and cash equivalents, accounts receivable, accounts payable, bank credit facilities, and term loan reported on the Consolidated Balance Sheets approximates their fair value. The fair value of the senior notes are considered a level 2 fair value measurement and details are disclosed in Note 17.

The Company uses the current expected credit loss model in valuing accounts receivable, which requires the use of a lifetime expected loss provision. In making an assessment as to whether financial assets are credit-impaired, the Company considers: (i) historically realized bad debts; (ii) a counterparty's present financial condition and whether a counterparty has breached certain contracts; (iii) the probability that a counterparty will enter bankruptcy or other financial reorganization; (iv) changes in economic conditions that correlate to increased levels of default; and (v) the term to maturity of the specified receivable. The carrying amounts of receivables are reduced by the amount of the expected credit loss through an allowance account and losses are recognized within general and administrative expense in the Consolidated Statement of Income/(Loss). If the Company subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account.

Enerplus has designated certain U.S. dollar denominated debt that is held in the parent entity as a hedge of its net investment in operations for which the U.S. dollar is the functional currency. As a non-derivative financial instrument, it will be accounted for under hedge accounting.

To be accounted for as a hedge, the U.S. dollar denominated debt must be designated as an effective hedge, both at inception and on an ongoing basis. The required hedge documentation defines the relationship between the U.S. dollar denominated debt and the net investment in the U.S. subsidiary, as well as the Company's risk management objective and strategy for undertaking the hedging transaction. The Company formally assesses, both at inception and on an ongoing basis, whether the changes in fair value of the U.S. dollar denominated debt are highly effective in offsetting changes in the fair value of the net investment in the U.S. subsidiary. If effective, the unrealized foreign exchange gains and losses arising from the translation of the U.S. denominated debt are recorded in Other Comprehensive Income/(Loss) ("OCI"), net of tax, to the extent the net investment in the U.S. subsidiary supports the U.S. denominated debt. Prior to January 1, 2020, the Company did not apply hedge accounting to the net investment in operations with a U.S. dollar functional currency, and unrealized gains and losses were recognized in net income/loss at the end of each respective reporting period.

A reduction in the fair value of the net investment in the U.S. subsidiary or increase in the U.S. dollar denominated debt may result in a portion of the hedge becoming ineffective. If the hedging relationship ceases to be effective or is terminated, hedge accounting is not applied and subsequent gains or losses are recorded through net income/(loss).

iii. Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations.

Enerplus has not designated its financial derivative contracts as effective accounting hedges and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, financial derivative contracts are classified as held-for-trading and are recorded at fair value based on a Level 2 designation, with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date. Enerplus' accounting policy is to not offset the fair values of its financial derivative assets and liabilities.

Realized gains and losses from commodity price risk management activities are recognized in income when the contract is settled. Unrealized gains and losses on commodity price risk management activities are recognized in income based on the changes in fair value of the contracts at the end of the respective reporting period.

Enerplus' crude oil, natural gas and natural gas liquids physical delivery purchase and sales contracts qualify as normal purchases and sales as they are entered into and held for the purpose of receipt or delivery of products in accordance with the Company's expected purchase, sale or usage requirements. As such, these contracts are not considered derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

m) Foreign Currency

i. Foreign currency transactions

Transactions denominated in foreign currencies are translated to the functional currency of the entity (Canadian dollars in Canada and U.S. dollars in the U.S) using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency of the entity using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Foreign currency differences arising on translation are recognized in net income in the period in which they arise.

ii. Foreign currency translation

For financial statement presentation, assets and liabilities of Enerplus' Canadian operations, which have a Canadian dollar functional currency, are translated into U.S. dollars at period end exchange rates while revenues and expenses are translated using average rates for the period. Gains and losses from the translation are deferred and included in the cumulative translation adjustment which is recorded in accumulated other comprehensive income.

n) Share-Based Compensation

Enerplus' share-based compensation plans include equity-settled Restricted Share Unit ("RSU") and Performance Share Unit ("PSU") awards made pursuant to its Share Award Incentive Plan ("SAIP"). The Company is authorized to issue up to 4.5% of outstanding common shares from treasury under the SAIP. Enerplus also has a cash-settled Deferred Share Unit ("DSU") Plan for Directors ("Director DSU Plan") and a cash-settled RSU Plan for Directors ("Director RSU Plan").

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

For RSU awards granted under the SAIP, employees receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and vests one-third each year for three years. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period.

For PSU awards granted under the SAIP, executives and management receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. The value upon vesting is based on the value of the underlying shares plus notional accrued dividends along with a multiplier that ranges from 0 to 2 depending on Enerplus' performance compared to a peer group of both Canadian and U.S. crude oil and natural gas producers over the vesting period.

Under Enerplus' Director DSU Plan and Director RSU Plan, directors receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual equity retainer value. Directors may elect to receive all or a portion of their notional shares under either plan. Under the Director DSU Plan, units vest and are paid at a specified date following the director leaving the Board. Under the Director RSU Plan, units vest one-third each year for three years. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period. All Director DSU and RSU grants are settled in cash.

Enerplus recognizes non-cash share-based compensation expense over the vesting period of the equity-settled long-term incentive plans, net of realized forfeitures, based on the estimated grant date share price fair value of the respective awards. The fair value for the PSUs is adjusted for the outcome of the performance condition. Share-based compensation charges are recorded on the Consolidated Statements of Income/(Loss) with an offset to paid-in capital. Each period, management performs an estimate of the PSU plan multiplier. Any differences that arise between the actual multiplier on plan settlement and management's estimate is recorded to share-based compensation. On settlement of these plans, amounts previously recorded to paid-in capital are reclassified to share capital.

Enerplus recognizes a liability with respect to its cash-settled long-term incentive plans based on their estimated fair value. The liability is re-measured at each reporting date and at settlement date with any changes in the fair value recorded as share-based compensation, included in general and administrative expense.

o) Net Income/(Loss) Per Share

Basic net income/(loss) per common share is computed by dividing net income/(loss) by the weighted average number of common shares outstanding during the period.

For the diluted net income per common share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income. The weighted average number of diluted shares is calculated in accordance with the treasury stock method which assumes that the proceeds received from outstanding RSU's and PSU's would be used to repurchase common shares at the average market price.

p) Contingencies

Liabilities for loss contingencies arising from claims, assessments, litigation, environmental and other sources are recognized when it is probable that a liability has been incurred and the amount can be reasonably estimated. Contingencies are adjusted as additional information becomes available or circumstances change.

q) Government Assistance

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

r) Accounting Changes and Recent Pronouncements Issued

Except for the changes below, the Company has consistently applied the accounting policies to all periods presented in these Consolidated Financial Statements, effective January 1, 2021:

- *ASU 2021-05 – Leases (Topic 842): Lessors – Certain leases with Variable Lease Payments.* The adoption of this standard had no impact on the financial statements.

3) ACQUISITIONS & DIVESTMENT

a) Bruin E&P HoldCo, LLC Acquisition

On January 25, 2021, Enerplus Resources (USA) Corporation, an indirect wholly-owned subsidiary of Enerplus entered into a purchase agreement to acquire all of the equity interests of Bruin E&P HoldCo, LLC ("Bruin") for total cash consideration of $465.0 million, subject to certain purchase price adjustments. Bruin was a private company that held crude oil and natural gas interests in certain properties located in the Williston Basin, North Dakota. The effective date of the acquisition was January 1, 2021 and the acquisition was completed on March 10, 2021.

The acquisition was funded through a new three-year $400 million term loan provided by a syndicate of financial institutions as well as a portion of the proceeds raised through a bought deal offering of common shares of the Company, which was completed on February 3, 2021. A total of 33,062,500 common shares were issued at a price of CDN$4.00 per common share for gross proceeds of approximately $103.4 million (net proceeds of $99.5 million).

The acquisition contributed $319.2 million to crude oil and natural gas revenues and $111.4 million to consolidated earnings before tax from the acquisition date to December 31, 2021. Transaction costs of $5.0 million were incurred for the year ended December 31, 2021.

If the transaction had occurred on January 1, 2021, the combined entity's unaudited pro-forma crude oil and natural gas revenues for the year ended December 31, 2021 would be $1,538.7 million (2020 – $775.2 million). For the year ended December 31, 2021 the combined entity would have had net income of $197.8 million (2020 – net loss of $1,332.7 million).

The unaudited pro-forma information may not be indicative of the results that actually would have occurred if the events reflected therein had been in effect on the dates indicated or of the results that may be obtained in the future. No pro forma adjustments were made to reflect operating synergies that resulted from the transaction.

Purchase Price Equation

The transaction was accounted for as an acquisition of a business. The purchase price is measured as the fair value of the assets transferred, equity instruments issued, and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date. The purchase price equation was determined following the closing date, during which time the value of the net assets and liabilities acquired was revised as indicated in the agreement and is reflected in the purchase price equation as follows:

($ thousands)	At March 10, 2021
Consideration	
Purchase Price	$ 465,000
Purchase price adjustments	(44,751)
Total consideration	$ 420,249
Fair value of identifiable assets and liabilities of Bruin	
Other current assets	1,667
Property, plant and equipment	542,190
Right of use assets	1,892
Accounts payable	(25,257)
Asset retirement obligation	(21,964)
Commodity contract liabilities	(76,387)
Lease liabilities	(1,892)
Total identifiable net assets	$ 420,249

The estimated fair value of the acquired property, plant and equipment was based on the after-tax cash-flows and associated proved and probable reserves discounted using an estimated weighted average cost of capital. The determination of proved and probable reserves involves numerous estimates and assumptions (see Note 2).

b) Dunn County Acquisition

On April 8, 2021, the Company announced it had entered into a purchase agreement to acquire assets in Dunn County, North Dakota from Hess Bakken Investments II, LLC for total cash consideration of $312.0 million, subject to customary purchase price adjustments. The acquisition was funded using the Company's existing cash balance with the remaining portion funded through borrowing on its bank credit facility. The effective date of the acquisition was March 1, 2021 and the acquisition closed on April 30, 2021.

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

c) Sleeping Giant and Russian Creek Divestment

On August 30, 2021, the Company announced it had entered into a definitive agreement to sell its interests in the Sleeping Giant field in Montana and the Russian Creek area in North Dakota in the Williston Basin, for total cash consideration of $115.0 million, subject to customary purchase price adjustments. After purchase price adjustments and transaction costs, adjusted proceeds were $107.8 million. In addition, Enerplus may receive up to $5.0 million in contingent payments if the WTI oil price averages over $65 per barrel in 2022 and over $60 per barrel in 2023, with amounts payable on January 31, 2023 and January 31, 2024, respectively. The disposition closed on November 2, 2021. The fair value of the contingent payments have been recorded as part of Other Long-Term assets.

4) ACCOUNTS RECEIVABLE

($ thousands)	December 31, 2021	December 31, 2020
Accrued revenue	$ 208,160	$ 73,201
Accounts receivable – trade	23,697	13,208
Allowance for doubtful accounts	(3,869)	(2,813)
Total accounts receivable, net of allowance for doubtful accounts	$ 227,988	$ 83,596

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

At December 31, 2021 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Crude oil and natural gas properties(1)	$ 13,075,987	$ (11,822,482)	$ 1,253,505
Other capital assets	103,355	(89,468)	13,887
Total PP&E	$ 13,179,342	$ (11,911,950)	$ 1,267,392

At December 31, 2020 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Crude oil and natural gas properties(1)	$ 11,966,258	$ (11,513,956)	$ 452,302
Other capital assets	96,373	(84,874)	11,499
Total PP&E	$ 12,062,631	$ (11,598,830)	$ 463,801

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

Acquisitions:

For the years ended December 31, 2021 and 2020, Enerplus acquired property and land totaling $857.1 million and $7.5 million, respectively. Refer to Note 3 for details regarding the Bruin and Dunn County acquisitions during 2021.

Divestments:

For the years ended December 31, 2021 and 2020, Enerplus disposed of properties for proceeds of $112.7 million and $4.5 million, respectively. Refer to Note 3 for details regarding the divestment of the Sleeping Giant and Russian Creek assets during 2021.

6) IMPAIRMENT

a) Impairment of PP&E

($ thousands)	2021	2020	2019
Crude oil and natural gas properties:			
U.S. cost centre	$ —	$ 650,780	$ —
Canada cost centre	3,420	100,943	—
Total impairment expense	$ 3,420	$ 751,723	$ —

For the year ended December 31, 2021, Enerplus recorded asset impairment of $3.4 million (2020 – $751.7 million; 2019 – nil). The primary factors that affect ceiling values include first-day-of-the-month commodity prices, reserves, capital expenditure levels and timing, acquisition and divestment activity, and production levels. At March 31, 2021, Enerplus' crude oil and natural gas properties in the U.S. cost centre exceeded the ceiling test limitation by approximately $265 million, primarily due to the difference in the ceiling value using SEC prices for the assets acquired in the Bruin acquisition compared to the carrying value, which more closely represented fair market value, based on forward prices. Given the short duration between closing the acquisition and the ceiling test calculation at March 31, 2021, Enerplus requested and received a temporary exemption from the SEC to exclude the properties acquired from Bruin in the full cost ceiling test for the duration of 2021.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling test at December 31, 2021, 2020 and 2019:

Period	WTI Crude Oil $/bbl	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas $/Mcf	Exchange Rate CDN$/US$
2021	$ 66.55	$ 78.15	$ 3.64	0.80
2020	39.54	45.56	2.00	0.75
2019	55.85	66.73	2.58	0.75

b) Impairment of Goodwill

At December 31, 2021 and 2020, there was no goodwill remaining on the Company's Consolidated Balance Sheets. During the year ended December 31, 2020, Enerplus recorded goodwill impairment of $149.2 million relating to its U.S. reporting unit. This was due to lower commodity prices in 2020, which resulted in a reduction in the fair value of the U.S. reporting unit. For the year ended December 31, 2019, Enerplus recorded goodwill impairment of $347.3 million relating to the Canadian reporting unit as a result of the cumulative impact of Canadian asset divestments, the shut-in of uneconomic natural gas production in Canada and lower forecasted commodity prices.

7) OTHER LONG-TERM ASSETS

Included in Other Long-term Assets is Company-owned line fill in third party pipelines, amounting to $5.3 million (December 31, 2020 – $3.8 million) and a long-term receivable amounting to $4.5 million (December 31, 2020 – nil) relating to the fair value of contingent consideration associated with the Sleeping Giant and Russian Creek divestment. The fair value is adjusted at each reporting period. See Note 3 for further details.

8) ACCOUNTS PAYABLE

($ thousands)	December 31, 2021	December 31, 2020
Accrued payables	$ 106,222	$ 84,286
Accounts payable – trade	260,786	113,609
Total accounts payable	$ 367,008	$ 197,895

9) DEBT

($ thousands)	December 31, 2021	December 31, 2020
Current:		
Senior notes	$ 100,600	$ 81,600
Long-term:		
Term loan	397,971	—
Senior notes	203,200	303,800
Total debt	$ 701,771	$ 385,400

Term Loan

Upon closing the Bruin acquisition on March 10, 2021, Enerplus entered into a three-year senior unsecured $400 million term loan. The drawn fees align with those of Enerplus' bank credit facility, which range between 125 and 315 basis points over bankers' acceptance or LIBOR rates. The term loan includes financial and other covenants consistent with Enerplus' bank credit facility and ranks equally with the bank credit facility and outstanding senior notes. Debt issuance costs of $2.8 million have been netted against the term loan and are being amortized over the three-year term. Subsequent to December 31, 2021, the Company converted its $400 million term loan into a revolving credit facility with no other amendments.

Bank Credit Facility

During 2021, Enerplus increased and extended its senior, unsecured, covenant-based bank credit facility to $900 million from $600 million with a maturity of October 31, 2025. Debt issuance costs of $1.8 million have been netted against the bank credit facility and are being amortized over the four and a half year term. As part of the extension, the Company transitioned the facility to a sustainability-linked credit facility incorporating environmental, social and governance ("ESG")-linked incentive pricing terms which reduce or increase the borrowing costs by up to 5 basis points as Enerplus' sustainability performance targets ("SPT") are exceeded or missed. The SPTs are based on the following ESG goals of the Company:

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

For the year ended December 31, 2021, total amortization of debt issuance costs amounted to $1.1 million (December 31, 2020 – nil).

Senior Notes

During 2021, Enerplus made its final $22.0 million principal repayment on its 2009 senior notes, and its second $59.6 million principal repayment on its 2012 senior notes. During 2020, Enerplus made its fourth $22.0 million principal repayment on its 2009 senior notes and its first $59.6 million principal repayment on its 2012 senior notes.

The terms and rates of the Company's outstanding senior notes are detailed below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	$200,000	$105,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	$20,000	$20,000
May 15, 2012	May 15 and Nov 15	3 equal annual installments beginning May 15, 2022	4.40%	$355,000	$178,800
				Total carrying value at December 31, 2021	$ 303,800

10) ASSET RETIREMENT OBLIGATION ("ARO")

($ thousands)	December 31, 2021	December 31, 2020
Balance, beginning of year	$ 102,325	$ 106,274
Change in estimates	26,586	3,020
Property acquisition and development activity	1,304	1,615
Bruin acquisition (Note 3)	21,964	—
Dunn County acquisition (Note 3)	5,880	—
Divestments (Note 3)	(13,525)	(758)
Settlements	(12,951)	(13,275)
Government assistance	(4,594)	—
Accretion expense	5,825	5,449
Balance, end of year	$ 132,814	$ 102,325

Enerplus has estimated the present value of its asset retirement obligation to be $132.8 million at December 31, 2021 based on a total undiscounted, uninflated liability of $303.3 million (December 31, 2020 – $102.3 million and $273.8 million, respectively). Enerplus' asset retirement obligation expenditures are mainly expected to be incurred between 2036 and 2051.

In 2021, Enerplus benefited from provincial government assistance to support the clean-up of inactive or abandoned crude oil and natural gas wells. These programs provide funding directly to oil field service contractors engaged by Enerplus to perform abandonment, remediation, and reclamation work. The funding received by the contractor is reflected as a reduction to ARO. For the year ended December 31, 2021, Enerplus benefited from $4.6 million (2020 – nil) in government assistance, which has been recorded as part of Other income in the Consolidated Statements of Income/(Loss).

11) LEASES

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

($ thousands)	December 31, 2021	December 31, 2020
Assets		
Operating right-of-use assets	$ 26,118	$ 25,818
Liabilities		
Current operating lease liabilities	$ 10,618	$ 10,523
Non-current operating lease liabilities	18,265	18,425
Total lease liabilities	$ 28,883	$ 28,948
Weighted average remaining lease term (years)		
Operating leases	3.3	3.9
Weighted average discount rate		
Operating leases	3.4%	4.2%

The Company's lease contract expenditures/(income) for the years ended December 31, 2021 and 2020 are as follows:

($ thousands)	2021	2020
Operating lease cost	$ 11,378	$ 12,368
Variable lease cost	633	1,308
Short-term lease cost	3,469	7,093
Sublease income	(1,083)	(1,101)
Total	$ 14,397	$ 19,668

Variable lease payments are determined through analysis of day rate fees under applicable rig contracts. The amounts in the table above are recorded as part of general and administrative or operating expenses or property, plant, and equipment depending on the nature of the contract to which they relate. Although Enerplus has various leases containing extensions and/or termination options, none were determined to be reasonably certain to be exercised. As a result, none of these options are recognized as part of the ROU assets or lease liabilities at December 31, 2021 or 2020.

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

($ thousands)	Operating Leases
2022	$ 11,419
2023	10,211
2024	5,870
2025	987
2026	966
After 2026	1,153
Total lease payments	$ 30,606
Less imputed interest	(1,723)
Total discounted lease payments	$ 28,883
Current portion of lease liabilities	$ 10,618
Non-current portion of lease liabilities	$ 18,265

Supplemental information related to leases is as follows:

($ thousands)	2021	2020
Cash amounts paid to settle lease liabilities:		
Operating cash flow used for operating leases	$ 11,571	$ 12,038
Right-of-use assets obtained/(terminated):		
Operating leases	$ 10,030	$ (1,306)

12) CRUDE OIL AND NATURAL GAS SALES

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

2021 ($ thousands)	Total revenue	Crude oil[1]	Natural gas[1]	Natural gas liquids[1]	Other[2]
United States	$ 1,355,255	$ 1,055,748	$ 219,552	$ 79,930	$ 25
Canada	127,320	111,070	11,127	4,348	775
Total	$ 1,482,575	$ 1,166,818	$ 230,679	$ 84,278	$ 800

2020 ($ thousands)	Total revenue	Crude oil[1]	Natural gas[1]	Natural gas liquids[1]	Other[2]
United States	$ 480,822	$ 380,074	$ 92,453	$ 8,182	$ 113
Canada	72,917	59,642	9,239	2,591	1,445
Total	$ 553,739	$ 439,716	$ 101,692	$ 10,773	$ 1,558

(1) U.S. sales of crude oil and natural gas relate primarily to the Company's North Dakota and Marcellus properties, respectively. Canadian crude oil sales relate primarily to the Company's waterflood properties.
(2) Includes third party processing income.

13) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	2021	2020	2019
General and administrative expense excluding share-based compensation[1]	$ 38,013	$ 33,347	$ 37,360
Share-based compensation expense	18,794	9,750	17,560
General and administrative expense	$ 56,807	$ 43,097	$ 54,920

(1) Includes non-cash lease credit of $365 in 2021, $212 in 2020, and an expense of $542 in 2019.

14) FOREIGN EXCHANGE

($ thousands)	2021	2020	2019
Realized:			
Foreign exchange (gain)/loss	$ 3,477	$ 771	$ (1,346)
Foreign exchange (gain)/loss on U.S. dollar cash held in parent company	(2,330)	(902)	6,825
Unrealized:			
Foreign exchange (gain)/loss on U.S. dollar debt and working capital in parent company	(8,055)	1,363	(21,899)
Foreign exchange (gain)/loss	$ (6,908)	$ 1,232	$ (16,420)

15) INCOME TAXES

Enerplus' provision for income tax is as follows:

($ thousands)	2021	2020	2019
Current tax			
United States	$ 2,700	$ (10,716)	$ (14,774)
Canada	(11)	—	(10,472)
Current tax expense/(recovery)	2,689	(10,716)	(25,246)
Deferred tax			
United States	$ 148,920	$ (167,835)	$ 53,020
Canada	(50,165)	(20,425)	8,630
Deferred tax expense/(recovery)	98,755	(188,260)	61,650
Income tax expense/(recovery)	$ 101,444	$ (198,976)	$ 36,404

The following provides a reconciliation of income taxes calculated at the Canadian statutory rate to the actual income taxes:

($ thousands)	2021	2020	2019
Income/(loss) before taxes			
United States	$ 544,464	$ (877,406)	$ 170,346
Canada	(208,579)	(14,921)	(338,342)
Total income/(loss) before taxes	335,885	(892,327)	(167,996)
Canadian statutory rate	24.00%	24.00%	26.50%
Expected income tax expense/(recovery)	$ 80,612	$ (214,158)	$ (44,519)
Impact on taxes resulting from:			
Foreign and statutory rate differences	$ 19,297	$ (27,918)	$ 21,329
Share-based compensation	1,878	1,671	(4,068)
Non-taxable capital (gains)/losses	(105)	14,341	3,007
Change in valuation allowance	(560)	(25,918)	(16,598)
Amounts in respect of prior periods	322	5,845	(14,669)
Non-deductible goodwill impairment and other expenses	—	47,161	91,922
Income tax expense/(recovery)	$ 101,444	$ (198,976)	$ 36,404

In 2020, the Alberta corporate income tax rate change resulted in a decrease to the Canadian statutory rate by 2.5%.

The deferred income tax asset consists of the following:

At December 31 ($ thousands)	2021	2020
Deferred income tax assets		
Property, plant and equipment	$ 125,312	$ 139,724
Tax loss carry-forwards and other credits	225,463	303,288
Capital loss carry-forwards and other capital items	107,681	111,497
Asset retirement obligation	32,896	24,985
Derivative financial instruments	28,907	2,926
Other assets	19,270	6,668
Deferred income tax assets before valuation allowance	539,529	589,088
Valuation allowance	(112,847)	(112,074)
Deferred income tax assets, net	426,682	477,014
Deferred income tax liabilities		
Property, plant and equipment	$ (45,824)	$ —
Total deferred income tax liabilities	(45,824)	—
Total deferred income tax asset	$ 380,858	$ 477,014

Loss carry-forwards available for tax reporting purposes:

At December 31 ($ thousands)	2021	Expiration Date
United States Federal		
Net operating losses – prior to 2018	$ 476,000	2032-2037
Net operating losses – 2018 and thereafter	256,000	Indefinite
Canada Federal		
Capital losses	$ 848,000	Indefinite
Non-capital losses	137,000	2031-2041

Changes in the balance of Enerplus' unrecognized tax benefits are as follows:

($ thousands)	2021	2020	2019
Balance, beginning of year	$ 15,485	$ —	$ 9,753
Increase – tax positions in prior periods	—	15,485	—
Settlements	—	—	(9,753)
Balance, end of year	$ 15,485	$ 15,485	$ —

If recognized, all of Enerplus' unrecognized tax benefits at December 31, 2021 would affect Enerplus' effective income tax rate. It is not anticipated that the amount of unrecognized tax benefits will significantly change during the next 12 months.

A summary of the taxation years, by jurisdiction, that remain subject to examination by the taxation authorities are as follows:

Jurisdiction	Taxation Years
United States – Federal	2018-2021
Canada – Federal	2017-2021

Enerplus and its subsidiaries file income tax returns primarily in Canada and the United States. Matters in dispute with the taxation authorities are ongoing and in various stages of completion.

16) SHAREHOLDERS' EQUITY

a) Share Capital

	2021		2020		2019	
(thousands)	Shares	Amount	Shares	Amount	Shares	Amount
Balance, beginning of year	222,548	$ 3,113,829	221,744	$ 3,106,875	239,411	$ 3,294,496
Issued/(Purchased) for cash:						
Issue of shares (net of tax effected issue costs)	33,062	99,516	—	—	—	—
Purchase of common shares under Normal Course Issuer Bid	(12,898)	(128,686)	(340)	(3,582)	(18,231)	(190,917)
Non-cash:						
Share-based compensation – treasury settled[(1)]	1,140	9,402	1,160	10,694	564	3,296
Cancellation of predecessor shares	—	—	(16)	(158)	—	—
Balance, end of year	243,852	$ 3,094,061	222,548	$ 3,113,829	221,744	$ 3,106,875

(1) The amount of shares issued on LTI settlement is net of employee withholding taxes.

The Company is authorized to issue an unlimited number of common shares without par value.

For the year ended December 31, 2021, Enerplus declared dividends of CDN$0.15 ($0.12) per weighted average common share totaling $30.5 million (2020 – CDN$0.12 ($0.09) per share and $20.0 million; December 31, 2019 – CDN$0.12 ($0.09) per share and $20.9 million). Subsequent to December 31, 2021, the Board of Directors approved a first quarter dividend payment of $0.033 per share to be paid in March 2022.

For the year ended December 31, 2021, Enerplus issued 33,062,500 common shares at a price of CDN$4.00 per common share for gross proceeds of $103.4 million (net $99.5 million, after $5.1 million in issue costs, net of $1.2 million in tax) pursuant to a bought deal prospectus offering under its base shelf prospectus.

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

On August 12, 2021 Enerplus received approval from the Toronto Stock Exchange ("TSX") to commence a Normal Course Issuer Bid ("NCIB") to purchase up to 10% of the public float (within the meaning under TSX rules) during a 12-month period. As a result, 12,897,721 common shares were repurchased and cancelled under the NCIB at an average price of $9.55 (CDN$12.06) per share, for total consideration of $123.2 million. Of the amount paid, $128.7 million was charged to share capital and $5.5 million was credited to accumulated deficit. At December 31, 2021, 12,668,090 common shares are available for repurchase under the current NCIB.

For the year ended December 31, 2020, the Company repurchased 340,434 common shares under the former NCIB at an average price of $5.63 (CDN$7.44) per share, for total consideration of $1.9 million. Of the amount paid, $3.6 million was charged to share capital and $1.7 million was credited to accumulated deficit.

For the year ended December 31, 2019, the Company repurchased 18,231,401 common shares under the former NCIB at an average price of $7.36 (CDN$9.80) per share, for total consideration of $134.3 million. Of the amount paid, $190.9 million was charged to share capital and $56.6 million was credited to accumulated deficit.

Subsequent to December 31, 2021 and up to and including February 23, 2022, the Company repurchased 2,257,400 common shares under the current NCIB at an average price of $11.58 (CDN$14.67) per share, for total consideration of $26.1 million.

b) Share-based Compensation

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

($ thousands)	2021	2020	2019
Cash:			
Long-term incentive plans (recovery)/expense	$ 6,875	$ (934)	$ 512
Non-Cash:			
Long-term incentive plans expense	13,789	9,720	16,814
Equity swap (gain)/loss	(1,870)	964	234
Share-based compensation expense	$ 18,794	$ 9,750	$ 17,560

LTI Plans

The following tables summarize the PSU, RSU and DSU activity for the year ended December 31, 2021:

For the year ended December 31, 2021	Cash-settled LTI Plans	Equity-settled LTI Plans		Total
(thousands of units)	DSU	PSU(1)	RSU	
Balance, beginning of year	555	2,552	1,825	4,932
Granted	269	2,158	2,207	4,634
Vested	(235)	(728)	(890)	(1,853)
Forfeited	—	—	(77)	(77)
Balance, end of year	589	3,982	3,065	7,636

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

Cash-settled LTI Plans

For the year ended December 31, 2021, the Company recorded a cash share-based compensation expense of $6.9 million (2020 – recovery of $0.9 million; 2019 – expense of $0.5 million).

At December 31, 2021, a liability of $6.3 million (December 31, 2020 – $1.7 million) with respect to the Director DSU Plan was recorded as part of Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

The following table summarizes the cumulative share-based compensation expense recognized to date which is recorded to Paid-in Capital on the Consolidated Balance Sheets. Unrecognized amounts will be recorded to non-cash share-based compensation expense over the remaining vesting terms.

At December 31, 2021 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 12,791	$ 10,554	$ 23,345
Unrecognized share-based compensation expense	9,050	4,303	13,353
Fair value	$ 21,841	$ 14,857	$ 36,698
Weighted-average remaining contractual term (years)	1.9	1.5	

(1) Includes estimated performance multipliers.

The Company directly withholds shares on PSU and RSU settlements for tax-withholding purposes. For the year ended December 31, 2021 cash withholding taxes of $3.6 million were paid (2020 – $5.6 million; 2019 – $3.7 million).

c) Basic and Diluted Net Income/(Loss) Per Share

Net income/(loss) per share has been determined as follows:

(thousands, except per share amounts)	2021	2020	2019
Net income/(loss)	$ 234,441	$ (693,351)	$ (204,400)
Weighted average shares outstanding – Basic	251,909	222,503	231,334
Dilutive impact of share-based compensation(1)	7,942	—	—
Weighted average shares outstanding – Diluted	259,851	222,503	231,334
Net income/(loss) per share			
Basic	$ 0.93	$ (3.12)	$ (0.88)
Diluted	$ 0.90	$ (3.12)	$ (0.88)

(1) For the years ended December 31, 2020 and 2019, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

17) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2021, the carrying value of cash and cash equivalents, accounts receivable, and accounts payable approximated their fair value due to the short-term nature of these instruments. The fair values of the bank credit facility and term loan approximate their carrying values as they bear interest at floating rates and the credit spread approximates current market rates.

At December 31, 2021, the senior notes had a carrying value of $303.8 million and a fair value of $304.1 million (December 31, 2020 – $385.4 million and $388.2 million, respectively). The fair value of the senior notes is estimated based on the amount that Enerplus would have to pay a third party to assume the debt, including the credit spread for the difference between the issue rate and the period end market rate. The period end market rate is estimated by comparing the debt to new issuances (secured or unsecured) and secondary trades of similar size and credit statistics for both public and private debt.

The fair value of derivative contracts, senior notes, term loan, and credit facility are considered level 2 fair value measurements. There were no transfers between fair value hierarchy levels during the year.

b) Derivative Financial Instruments

The derivative financial assets and liabilities on the Consolidated Balance Sheets are recorded at amounts that represent the fair values of these instruments. At December 31, 2021, Enerplus has equity, commodity, and contingent consideration contracts. See Note 7 regarding the contingent consideration contract.

The following tables summarize the change in fair value associated with equity and commodity contracts for the respective years:

Gain/(Loss) ($ thousands)	2021	2020	2019	Income Statement Presentation
Equity Swaps	$ 1,870	$ (964)	$ (234)	G&A expense
Commodity Contracts:				
Oil	(111,655)	(19,891)	(51,479)	Commodity derivative instruments
Gas	249	2,781	(8,037)	
Total Unrealized Gain/(Loss)	$ (109,536)	$ (18,074)	$ (59,750)	

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

($ thousands)	2021	2020	2019
Unrealized change in fair value gain/(loss)	$ (111,406)	$ (17,110)	$ (59,516)
Net realized cash gain/(loss)	(163,026)	92,852	11,586
Commodity contracts gain/(loss)	$ (274,432)	$ 75,742	$ (47,930)

The following table summarizes the presentation of fair values on the Consolidated Balance Sheets:

	December 31, 2021			December 31, 2020	
	Assets	Liabilities		Assets	Liabilities
($ thousands)	Current	Current	Long-term	Current	Current
Equity Swaps	$ —	969	$ —	$ —	$ 2,839
Commodity Contracts:					
Oil	1,771	141,364	7,098	—	12,297
Gas	3,897	867	—	2,790	—
Total	$ 5,668	143,200	$ 7,098	$ 2,790	$ 15,136

The fair value of commodity contracts and the equity swaps is estimated based on commodity and option pricing models that incorporate various factors including forecasted commodity prices, volatility and the credit risk of the entities party to the contract. Changes and variability in commodity prices over the term of the contracts can result in material differences between the estimated fair value at a point in time and the actual settlement amounts.

On March 10, 2021, the outstanding crude oil commodity contracts acquired with the Bruin acquisition were recorded at fair value. Realized and unrealized gains and losses on the acquired contracts are recognized in the Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the closing date of the Bruin acquisition.

At December 31, 2021, the fair value of Enerplus' commodity contracts totaled a net liability of $143.7 million. Of this total net liability, $40.2 million related to Bruin contracts, with $22.8 million remaining from the original $76.4 million liability acquired from Bruin.

c) Risk Management

In the normal course of operations, Enerplus is exposed to various market risks, including commodity prices, foreign exchange, interest rates, equity prices, credit risk, liquidity risk, and the risks associated with environmental/climate change risk, social and governance regulation, and compliance.

i) Market Risk

Market risk is comprised of commodity price, foreign exchange, interest rate and equity price risk.

Commodity Price Risk:

Enerplus manages a portion of commodity price risk through a combination of financial derivative and physical delivery sales contracts. Enerplus' policy is to enter into commodity contracts subject to a maximum of 80% of forecasted production volumes.

The following tables summarize Enerplus' price risk management positions at February 24, 2022:

Crude Oil Instruments:

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

(1) The total average deferred premium spent on the Company's outstanding crude oil contracts is $1.50/bbl from January 1, 2022 - December 31, 2022 and $1.25/bbl from January 1, 2023 – June 30, 2023.
(2) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(3) Upon closing of the Bruin Acquisition, Bruin's outstanding crude oil contracts were recorded at a fair value liability of $76.4 million. At December 31, 2021, the balance was a liability of $22.8 million on the Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired contracts are recognized in Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets to reflect changes in crude oil prices from the date of closing of the Bruin Acquisition.

Natural Gas Instruments:

Instrument Type[1]	**MMcf/day**	**$/Mcf**
Jan 1, 2022 – Feb 28, 2022		
NYMEX Purchased Put	40.00	3.43
NYMEX Sold Call	40.00	6.00
Mar 1, 2022 – Mar 31, 2022		
NYMEX Swap	60.00	4.50
NYMEX Purchased Put	40.00	3.43
NYMEX Sold Call	40.00	6.00
Apr 1, 2022 – Oct 31, 2022		
NYMEX Swap	40.00	3.40
NYMEX Purchased Put	60.00	3.77
NYMEX Sold Call	60.00	4.50

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

Foreign Exchange Risk & Net Investment Hedge:

Enerplus is exposed to foreign exchange risk as it relates to certain activity transacted in Canadian or United States dollars. Enerplus has a U.S. dollar reporting currency, however Enerplus' parent company has a Canadian functional currency. Activity in the Canadian parent company that is transacted in U.S. dollars will result in realized and unrealized foreign exchange gains and losses that will be recorded on the Consolidated Statements of Income/(Loss).

Enerplus may designate certain U.S. dollar denominated debt held in the parent entity as a hedge of its net investment in its U.S. subsidiary, which has a U.S. dollar functional currency. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in Other Comprehensive Income/(Loss), net of tax, and are limited by the cumulative translation gain or loss on the net investment in the foreign subsidiary. At December 31, 2021, $303.8 million of senior notes and the $400 million term loan were designated as net investment hedges (2020 – $385.4 million of senior notes). For the year ended December 31, 2021, Other Comprehensive Income/(Loss) included an unrealized gain of $4.1 million on Enerplus' U.S denominated senior notes and term loan (2020 – $1.8 million gain and 2019 – nil).

Interest Rate Risk:

The Company's senior notes bear interest at fixed rates while the term loan and bank credit facility bear interest at floating rates. At December 31, 2021, approximately 43% of Enerplus' debt was based on fixed interest rates and 57% on floating interest rates (December 31, 2020 – 100% fixed), with weighted average interest rates of 4.2% and 1.9%, respectively (December 31, 2020 – 4.4%). At December 31, 2021 and 2020, Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 16. Enerplus has entered into various equity swaps maturing in 2022 that effectively fix the future settlement cost on a portion of its cash settled LTI plans.

ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables. Enerplus has appropriate policies and procedures in place to manage its credit risk; however, given the volatility in commodity prices, Enerplus is subject to an increased risk of financial loss due to non-performance or insolvency of its counterparties.

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

The Company's maximum credit exposure consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At December 31, 2021, approximately 83% of Enerplus' marketing receivables were with companies considered investment grade (December 31, 2020 – 82%).

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2021 was $3.9 million (December 31, 2020 – $2.8 million).

iii) Liquidity Risk & Capital Management

Liquidity risk represents the risk that Enerplus will be unable to meet its financial obligations as they become due. Enerplus mitigates liquidity risk through actively managing its capital, which it defines as debt (net of cash and cash equivalents) and shareholders' capital. Enerplus' objective is to provide adequate short and longer term liquidity while maintaining a flexible capital structure to sustain the future development of its business. Enerplus strives to balance the portion of debt and equity in its capital structure given its current crude oil and natural gas assets and planned investment opportunities.

Management monitors a number of key variables with respect to its capital structure, including debt levels, capital spending plans, dividends, share repurchases, access to capital markets, as well as acquisition and divestment activity.

At December 31, 2021, Enerplus was in full compliance with all covenants under the bank credit facility, term loan and outstanding senior notes. If the Company breaches or anticipates breaching its covenants, the Company may be required to repay, refinance, or renegotiate the terms of the debt.

iv) Climate Change Risk

The following provides certain considerations as to the impact of climate change on the amounts recorded in the financial statements for the year ended December 31, 2021. The below is not a comprehensive list or analysis of all climate change impacts and risks. In addition, the focus is with respect to the impact of climate change on amounts recognized in the Company's financial statements as at and for the year ended December 31, 2021.

Changing regulation

Emissions, carbon and other regulations impacting climate and climate related matters are constantly evolving. The Canadian Securities Administrators have issued a proposed National Instrument 51-107 *Disclosure of Climate-related Matters.* The cost to comply with these standards, and others that may be developed or evolve over time, has not been quantified.

Impact of climate events and change on amounts recorded in the 2021 financial statements

Reserves:

The Company engages a third party external reserve engineer to review the reserve report. Enerplus considers the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels in its assessment of economic recovery of crude oil and natural gas reserves. The reserve report includes anticipated impacts from emissions related taxes, most notably the reserve report includes estimated carbon tax related to the Company's operations.

Ceiling test:

Given the prescriptive nature of the ceiling test and depletion calculations, climate change risk is only considered in the determination of reserves, which will impact the ceiling test and depletion calculations. At December 31, 2021, no impairment was recorded as a result of the ceiling test completed. See Note 6 for further detail.

Expenditures on property, plant and equipment:

The Company incurs capital expenditures related to emissions reduction initiatives. The extent of spending on projects directly linked to reducing the climate impact of the Company's operations will vary, however, management anticipates funding future projects through cash flow from operations and bank credit facilities.

Current assets and current liabilities:

These amounts are short term in nature and management is not aware of any material impacts on these items related to climate change and climate events. The Company did not experience credit losses on its accounts receivable during 2021.

Access to Capital :

There is risk that access to capital may be restricted to the oil and gas industry. Management plans to continue to monitor and adjust the capital structure where necessary. During 2021, Enerplus transitioned its bank credit facility to a SLL facility with three sustainability performance targets. See Note 9 for further detail.

Physical effects of climate events (i.e. fire, flood, extreme weather) on the financial results

The Company's financial results for 2021 were not impacted by a climate event.

18) COMMITMENTS AND CONTINGENCIES

a) Commitments

Enerplus has the following minimum annual commitments, excluding operating leases which are recorded in the lease liability (see Note 11):

		Minimum Annual Commitment Each Year					
($ thousands)	Total	2022	2023	2024	2025	2026	Thereafter
Senior notes[(1)]	$ 303,800	$ 100,600	$ 80,600	$ 80,600	$ 21,000	$ 21,000	$ —
Term Loan[(1)]	400,000	—	—	400,000	—	—	—
Transportation commitments	545,636	72,241	72,802	73,201	74,014	74,464	178,914
Processing commitments	6,311	1,202	1,202	1,206	1,202	1,202	297
Service Workover Rigs Commitments	9,828	7,884	1,944	—	—	—	—
Total commitments[(2)(3)]	$ 1,265,575	$ 181,927	$ 156,548	$ 555,007	$ 96,216	$ 96,666	$ 179,211

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) CDN$ commitments have been converted to US$ using the December 31, 2021 foreign exchange rate of 0.79.

b) Contingencies

Enerplus is subject to various legal claims and actions arising in the normal course of business. Although the outcome of such claims and actions cannot be predicted with certainty, the Company does not expect these matters to have a material impact on the Consolidated Financial Statements. In instances where the Company determines that a loss is probable and the amount can be reasonably estimated, an accrual is recorded.

19) GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2021 ($ thousands)	U.S.	Canada	Total
Crude oil and natural gas sales	$ 1,355,255	$ 127,320	$ 1,482,575
Depletion, depreciation and accretion	246,949	24,387	271,336
Property, plant and equipment	1,179,070	88,322	1,267,392
Deferred income tax asset	162,582	218,276	380,858

As at and for the year ended December 31, 2020 ($ thousands)	U.S.	Canada	Total
Crude oil and natural gas sales	$ 480,822	$ 72,917	$ 553,739
Depletion, depreciation and accretion	183,226	34,892	218,118
Property, plant and equipment	375,634	88,167	463,801
Deferred income tax asset	311,502	165,512	477,014

As at and for the year ended December 31, 2019 ($ thousands)	U.S.	Canada	Total
Crude oil and natural gas sales	$ 812,370	$ 133,524	$ 945,894
Depletion, depreciation and accretion	223,874	45,172	269,046
Property, plant and equipment	1,007,001	199,782	1,206,783
Deferred income tax asset	143,666	143,094	286,760
Goodwill	149,357	—	149,357
Long term income tax receivable	10,664	—	10,664

20) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	December 31, 2021	December 31, 2020	December 31, 2019
Accounts receivable	$ (144,413)	$ 84,685	$ (255)
Other assets	(7,583)	(3,333)	3,177
Accounts payable - operating	57,353	2,317	(6,119)
Non-cash operating activities	$ (94,643)	$ 83,669	$ (3,197)

b) Changes in Non-Cash Financing Working Capital

($ thousands)	December 31, 2021	December 31, 2020	December 31, 2019
Dividends payable	$ (1,749)	$ 65	$ (96)
Non-cash financing activities	$ (1,749)	$ 65	$ (96)

c) Changes in Non-Cash Investing Working Capital

($ thousands)	December 31, 2021	December 31, 2020	December 31, 2019
Accounts payable - investing(1)	$ 32,793	$ (28,390)	$ 15,724
Non-cash investing activities(1)	$ 32,793	$ (28,390)	$ 15,724

(1) Relates to changes in accounts payable for capital and office expenditures and included in capital and office expenditures on the Consolidated Statements of Cash Flows, with the exclusion of the Bruin and Dunn County acquisitions. See Note 3.

During the year ended December 31, 2021, Enerplus, received a $4.6 million distribution associated with a privately held investment. This distribution is recorded within Transaction costs and other expense/(income) on the Consolidated Statements of Income/(Loss), and reflected as an investing activity on the Consolidated Statements of Cash Flows.

d) Cash Income taxes and Interest payments

($ thousands)	December 31, 2021	December 31, 2020	December 31, 2019
Income taxes paid/(received)	$ 5,500	$ (42,716)	$ (53,674)
Interest paid	$ 25,808	$ 21,276	$ 25,517

21) SUBSEQUENT EVENT

On February 2, 2022, the Company announced its plan to initiate a divestment process for its Canadian assets. Production from its Canadian assets averaged approximately 7,200 BOE/day in 2021.

ABBREVIATIONS

bbl(s)/day barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S. gallons

Bcf billion cubic feet

BOE[1] barrels of oil equivalent

Brent crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.

DAPL Dakota Access pipeline

LTI long-term incentive

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

MMcf million cubic feet

MMBOE million barrels of oil equivalent

MSW Mixed Sweet Blend is the benchmark for conventionally produced light sweet crude for Western Canada

NCIB Normal Course Issuer Bid

NGL natural gas liquid

NI 51-101 National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory Authorities (pertaining to reserves reporting in Canada)

NYMEX New York Mercantile Exchange, the benchmark for North American natural gas pricing

2P Reserves proved plus probable reserves

RLI reserves life index

SBC share based compensation

SEC United States Securities and Exchange Commission

Transco Leidy Price benchmark for Marcellus natural gas delivered into the Transco pipeline system between Hunterdon County, New Jersey and connections east of the Leidy storage facility in Clinton and Potter Counties in Pennsylvania

Transco Z6 Non-New York Price benchmark for Marcellus natural gas delivered into the Transco pipeline system from the start of zone 6 at the Virginia-Maryland border to the Linden, New Jersey, compressor station and on the 24-inch pipeline to the Wharton, Pennsylvania, station

U.S. GAAP accounting principles generally accepted in the United States of America

WCS Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes

WTI West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

(1) The Corporation has adopted the standard of 6 Mcf of natural gas: 1 bbl of oil when converting natural gas to BOEs, MBOEs and MMBOEs, and 1 bbl of oil and NGLs: 6 Mcf of natural gas when converting oil and NGLs to BcfGEs. For further information, see "*Presentation of Oil and Gas Reserves*, *Contingent Resources and Production Information – Barrels of Oil and Cubic Feet of Gas Equivalent*" in the Annual Information Form.

BOE Barrels of oil equivalent converting 6 Mcf of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. The factor used to convert natural gas and natural gas liquids to oil equivalent is not based on either energy content or prices but is a commonly used industry benchmark. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 BOE is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Future Development Costs (FDC) Future Development Costs is defined as those costs which reflect the independent evaluator's best estimate of what it will cost to bring the proved and probable non-producing and undeveloped reserves on production in the future. Changes to this figure occur annually as a result of development activities, acquisition and disposition activities, additions to non-producing and undeveloped reserves and capital cost estimate revisions.

F&D Costs Finding and development costs. It is a measure of the effectiveness of a company's capital program. F&D costs presented are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding and development costs related to its reserves additions for that year. F&D costs are presented in United States dollars per working interest BOE unless otherwise specified.

FD&A Costs Finding, development and acquisition costs. It is a measure of a company's ability to add reserves in a cost-effective manner. FD&A costs presented are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year. FD&A costs are presented in United States dollars per working interest BOE unless otherwise specified.

NGLs Natural gas liquids – hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

Production, Company Interest Our working interest (operated and non-operated) share of production before the deduction of royalties, but inclusive of any royalty interest production owned by Enerplus. Therefore, the "company interest" production of the Corporation may not be comparable to similar measures presented by other issuers, and investors are cautioned that "company interest" production should not be construed as an alternative to "gross" or "net" production calculated in accordance with Canadian NI 51-101 Standards.

Production, Net Our working interest (operated and non-operated) share after deduction of royalty obligations, plus our royalty interests in production. Unless otherwise stated, all production volumes utilized in any discussions or calculations are net production volumes.

Reserves, Gross Our working interest (operated and non-operated) share of reserves before the deduction of any royalty interest reserves but exclusive of royalty interest reserves owned by Enerplus.

Reserves, Net Our working interest (operated and non-operated) share of reserves after the deduction of royalty interest reserves but inclusive of any royalty interest reserves owned by Enerplus.

Reserves, Probable Additional reserves, calculated in accordance with Canadian NI 51-101 Standards, that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Reserves, Proved Reserves that can be estimated with a high degree of certainty to be recoverable in accordance with Canadian NI 51-101 Standards or U.S. Standards. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Reserves, Developed Producing Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

BOARD OF DIRECTORS

Hilary A. Foulkes(1)(2)

Corporate Director
Calgary, Alberta

Judith D. Buie(3)(5)(7)

Corporate Director
Houston, Texas

Karen E. Clarke-Whistler(3)(7)(9)

Corporate Director
Toronto, Ontario

Ian C. Dundas

President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Robert B. Hodgins(4)(9)

Corporate Director
Calgary, Alberta

Susan M. MacKenzie(7)(10)

Corporate Director
Calgary, Alberta

Jeffrey W. Sheets(6)(9)

Corporate Director
Houston, Texas

Sheldon B. Steeves(5)(8)

Corporate Director
Calgary, Alberta

(1) Chair of the Board
(2) *Ex-Officio* member of all Committees of the Board
(3) Member of the Corporate Governance & Nominating Committee
(4) Chair of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chair of the Audit & Risk Management Committee
(7) Member of the Reserves, Safety & Social Responsibility Committee
(8) Chair of the Reserves, Safety & Social Responsibility Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chair of the Compensation & Human Resources Committee

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas

President &
Chief Executive Officer

Wade D. Hutchings

Senior Vice-President &
Chief Operating Officer

Jodine J. Jenson Labrie

Senior Vice-President &
Chief Financial Officer

Garth R. Doll

Vice-President, Marketing

Terry S. Eichinger

Vice-President, Drilling, Completions & Operations Support

Nathan D. Fisher

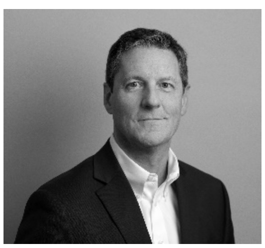
Vice-President, United States Business Unit

Daniel J. Fitzgerald

Vice-President, Business Development

John E. Hoffman

Vice-President, Digital Technology & Corporate Sustainability



David A. McCoy

Vice-President, General Counsel & Corporate Secretary

Shaina B. Morihira

Vice-President, Finance

CORPORATE INFORMATION

Operating Companies Owned by Enerplus Corporation

Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
KPMG LLP
Calgary, Alberta

Transfer Agent
TSX Trust (Canada)
Toronto, Ontario
Toll free: 1.866.600.5869

American Stock Transfer & Trust Company (United States)
Brooklyn, New York
Toll free: 1.800.937.5449

Independent Reserves Engineers
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Netherland, Sewell & Associates, Inc.
Dallas, Texas

Stock Exchange Listings and Trading Symbols
Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

U.S. Office
U.S. Bank Tower
Suite 2200, 950 - 17th Street
Denver, Colorado 80202-2805

Telephone: 720.279.5500
Fax: 720.279.5550

ENERPLUS
The Dome Tower
3000, 333 7th Avenue SW
Calgary, Alberta, Canada
T2P 2Z1
Telephone: 403.298.2200
Toll Free 1.800.319.6462
Fax: 403.298.2211

ENERPLUS RESOURCES (USA) CORPORATION
Suite 2200
950 17th Street
Denver, Colorado United States
80202-2805
Telephone: 720.279.5500
Fax: 720.729.5550

www.enerplus.com
investorrelations@enerplus.com

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