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NEWS RELEASE

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Enerplus Announces Fourth Quarter and Full Year 2020 Financial and Operating Results and 2020 Year End Reserves

All financial information contained within this news release has been prepared in accordance with U.S. GAAP. This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review the "Forward-Looking Information and Statements" at the conclusion of this news release. Readers are also referred to "Information Regarding Reserves, Resources and Operational Information", "Notice to U.S. Readers" and "Non-GAAP Measures" at the end of this news release for information regarding the presentation of the financial, reserves, contingent resources and operational information in this news release, as well as the use of certain financial measures that do not have standard meaning under U.S. GAAP. A copy of Enerplus' 2020 Financial Statements and MD&A is available on our website at www.enerplus.com, under our profile on SEDAR at www.sedar.com and on the EDGAR website at www.sec.gov. All amounts in this news release are stated in Canadian dollars unless otherwise specified.

Calgary, Alberta - Enerplus Corporation ("Enerplus" or the "Company") (TSX & NYSE: ERF) today reported fourth quarter 2020 cash flow from operating activities and adjusted funds flow of $96.1 million and $91.9 million, respectively, compared to $188.5 million and $178.9 million, respectively, in the fourth quarter of 2019. Full year 2020 cash flow from operating activities and adjusted funds flow was $446.4 million and $358.2 million, respectively, compared to $694.2 million and $709.0 million, respectively, in 2019. Cash flow from operating activities and adjusted funds flow decreased from 2019 due to lower benchmark crude oil prices and reduced production volumes.

FULL YEAR 2020 SUMMARY AND ANNOUNCED ACQUISITION

- **Generated free cash flow in 2020 –** Adjusted funds flow was $358.2 million in 2020, which exceeded capital spending of $291.4 million, generating free cash flow of $66.8 million.
- **Enhanced free cash flow outlook –** Upon closing of the recently announced acquisition of Bruin E&P HoldCo, LLC ("Bruin"), anticipated in early March 2021, Enerplus expects to see a material increase in its free cash flow generation. Pro forma and based on a ten-month contribution from Bruin's assets in 2021, Enerplus expects to generate over $300 million of free cash flow in 2021 based on US$55 per barrel WTI crude oil and US$3.00 per Mcf NYMEX natural gas prices.
- **Maintaining a solid balance sheet –** Despite the low commodity price environment in 2020, Enerplus ended the year with a net debt to adjusted funds flow ratio of 1.0x and was undrawn on its US$600 million bank credit facility. Pro forma for the announced acquisition of Bruin, including the associated equity and term facility financings, Enerplus expects to remain in a resilient financial position with excellent liquidity. Enerplus estimates its year end 2021 net debt to adjusted funds flow ratio to be approximately 1.0x based on US$55 per barrel WTI crude oil and US$3.00 per Mcf NYMEX natural gas prices.
- **Business resilience and safe operations –** Enerplus successfully adapted to new remote working practices and enhanced safety measures due to the COVID-19 pandemic; achieving the best safety performance in the Company's history based on lost time injury frequency.
- **Capital efficiency improvement –** Solid operational execution delivered a step change in well cost performance in North Dakota with a 17% reduction (US$1.3 million per well) year-over-year. Proved plus probable finding and development ("F&D") costs were $6.50 per BOE in 2020, over 40% lower than the Company's prior three year average.
- **Strong performance relative to environmental targets –** Reduced 2020 greenhouse gas ("GHG") emissions intensity by more than 20% year-over-year based on preliminary estimates (target reduction was 10%). Reduced 2020 freshwater use per well completion in North Dakota by 23% year-over-year (target reduction was 15%).

"I want to thank our workforce for their efforts in the face of a challenging 2020," said Ian C. Dundas, President and CEO of Enerplus. "Their commitment to keeping each other and our communities safe as we adapted to a complicated new environment battling the spread of COVID-19 was exceptional. It was also critical to ensuring the continuity of our operations."

"Despite the volatile market conditions in 2020, we were able to preserve shareholder value, maintain our strong financial footing and position the business to deliver differentiated shareholder returns going forward. Our announced acquisition of Bruin, expected to close in early March 2021, demonstrates our ongoing commitment to value creation for shareholders, enabling us to accelerate free cash flow growth and further support our focus on providing long term sustainable returns."

FOURTH QUARTER 2020 SUMMARY

Enerplus delivered fourth quarter production at the high end of its guidance ranges with total production of 86,244 BOE per day (guidance was 84,000 to 87,000 BOE per day), including crude oil and natural gas liquids production of 49,195 barrels per day (guidance was 47,000 to 49,000 barrels per day). Total production in the fourth quarter was 5% lower than the prior quarter and 20% lower than same period in 2019. Liquids production in the fourth quarter of 2020 was 6% lower than the prior quarter and 18% lower than same period in 2019. The lower quarter-over-quarter production was due to limited capital activity. The lower production compared to the same period in 2019 was due to the significant reduction in capital activity in North Dakota during 2020 in response to the decline in crude oil prices, as well as lower capital activity in the Company's Marcellus natural gas asset during 2020.

Enerplus reported a fourth quarter 2020 net loss of $204.2 million, or ($0.92) per share, compared to a net loss of $429.1 million, or ($1.93) per share, in the fourth quarter of 2019. The reduced net loss was primarily due to lower non-cash impairment charges in the fourth quarter of 2020. The Company recognized a $311.2 million non-cash property, plant and equipment ("PP&E") impairment in the fourth quarter of 2020 due to the low commodity price environment and the use of 12-month trailing prices to test for impairment under the Securities and Exchange Commission ("SEC") guidelines. Excluding the PP&E impairment and certain other non-cash or non-recurring items, fourth quarter 2020 adjusted net income was $22.1 million, or $0.10 per share, compared to $34.4 million, or $0.15 per share, during the same period in 2019. Adjusted net income decreased from the fourth quarter of 2019 due to lower benchmark crude oil prices and reduced production volumes.

Enerplus' fourth quarter 2020 Bakken crude oil price differential was US$4.82 per barrel below WTI, compared to US$4.40 per barrel below WTI for the same period in 2019. The weaker differential compared to the prior year period was due to the narrowing of Brent-WTI differentials. Enerplus' fourth quarter Marcellus natural gas price differential was US$1.07 per Mcf below NYMEX, compared to US$0.63 per Mcf below NYMEX for the same period in 2019. Regional pricing in the Marcellus was particularly weak from September to November of 2020 due to nearly full regional storage combined with low demand due to mild weather.

Operating expenses in the fourth quarter of 2020 were $8.20 per BOE, compared to $8.05 per BOE in the same period in 2019. The increase in per unit operating expenses was due to lower production in the fourth quarter of 2020. Cash general and administrative ("G&A") expenses were $1.46 per BOE in the fourth quarter of 2020, compared to $1.34 per BOE in the prior year period. The increase in per unit G&A expenses was also due to lower production in the fourth quarter of 2020.

Exploration and development capital spending totaled $52.4 million in the fourth quarter of 2020. The Company paid $6.7 million in dividends during the quarter.

Enerplus ended the fourth quarter of 2020 with total debt net of cash of $376.0 million and was undrawn on its US$600 million bank credit facility. The Company's net debt to adjusted funds flow ratio was 1.0 times at quarter-end.

FULL YEAR 2020 SUMMARY

Enerplus delivered 2020 production at the high end of its annual guidance ranges with total production of 90,697 BOE per day (guidance was 90,000 to 91,000 BOE per day), including crude oil and natural gas liquids production of 51,054 barrels per day (guidance was 50,500 to 51,000 barrels per day). Total production and liquids production decreased 10% and 7%, respectively, compared to 2019. The year-over-year decrease in liquids production was due to the temporary curtailment of crude oil production during the second quarter and the significant reduction in capital activity in North Dakota during 2020 in response to the decline in crude oil prices. Natural gas production decreased 15% year-over-year due to lower capital activity in the Company's Marcellus natural gas asset during 2020.

Enerplus reported a full year 2020 net loss of $923.4 million, or ($4.15) per share, compared to a net loss of $259.7 million, or ($1.12) per share, in 2019. The higher net loss was primarily due to larger non-cash impairment charges, lower benchmark crude oil prices and reduced production volumes in 2020. The Company recognized non-cash impairments totaling $1,197.6 million in 2020 related to PP&E and goodwill due to the low commodity price environment and the use of 12-month trailing prices to test for impairment under the SEC guidelines. Excluding these impairments and certain other non-cash or non-recurring items, full year 2020 adjusted net income was $19.8 million, or $0.09 per share, compared to $243.2 million, or $1.05 per share, in 2019. Adjusted net income decreased from 2020 due to lower benchmark crude oil prices and reduced production volumes.

Enerplus' 2020 Bakken crude oil price differential was US$4.96 per barrel below WTI, compared to US$3.61 per barrel below WTI in 2019. The weaker year-over-year differential was due to the significant benchmark oil price volatility and the narrowing of Brent-WTI differentials throughout the year. Enerplus' 2020 Marcellus natural gas price differential was US$0.65 per Mcf below NYMEX, compared to US$0.39 per Mcf below NYMEX in 2019. Regional pricing in the Marcellus was particularly weak from September to November of 2020 due to nearly full regional storage combined with low demand due to mild weather.

Operating expenses in 2020 were $7.94 per BOE, compared to $7.88 per BOE in 2019. Cash G&A expenses in 2020 were $1.35 per BOE, compared to $1.32 per BOE in 2019.

Exploration and development capital spending totaled $291.4 million in 2020, below the Company's capital budget guidance of $295 million. The Company paid $26.7 million in dividends in 2020.

2020 YEAR END RESERVES SUMMARY

- Total proved plus probable ("2P") reserves were 424.4 MMBOE at year end 2020, 4% lower than year end 2019.
- Enerplus replaced 50% of total 2020 production, adding 16.7 MMBOE of 2P reserves (including technical revisions and economic factors). In North Dakota, the Company replaced 69% of 2020 production, adding 11.3 MMBOE of 2P reserves.
- Excluding economic factors, Enerplus replaced 89% of total 2020 production, adding 29.2 MMBOE of 2P reserves. In North Dakota, the Company replaced 119% of 2020 production excluding economic factors, adding 19.4 MMBOE of 2P reserves. Economic factors are reserves revisions due to the significant reduction in year-over-year forecast prices.
- F&D costs were $26.51 per BOE for proved developed producing ("PDP") reserves, $6.78 per BOE for proved reserves, and $6.50 per BOE for 2P reserves, including future development costs ("FDC").
- Finding, development and acquisition ("FD&A") costs were $6.97 per BOE for proved reserves and $6.74 per BOE for 2P reserves, including FDC.

ASSET ACTIVITY

Williston Basin production averaged 46,127 BOE per day during the fourth quarter of 2020, 5% lower than the prior quarter and 15% lower than the same period in 2019. Fourth quarter Williston Basin production was comprised of 43,641 BOE per day in North Dakota and 2,486 BOE per day in Montana. In the fourth quarter, the Company brought four operated wells on production (100% working interest). No operated wells were drilled in the fourth quarter. Full year 2020 production from the Williston Basin averaged 47,125 BOE per day, a 3% decrease year-over-year. Enerplus delivered meaningful reductions to its well cost structures in 2020 driven by solid planning and execution coupled with technology application. This led to a continuing trend of improved drilling and completion cycle times resulting in an average total well cost of US$6.3 million in 2020, approximately 17% lower than 2019.

Marcellus shale gas production averaged 175 MMcf per day during the fourth quarter of 2020, 5% lower than the prior quarter and 25% lower than the same period in 2019. In the fourth quarter, the Company participated in drilling 23 gross non-operated wells (7% average working interest) with 19 gross non-operated wells (6% average working interest) brought on production. Full year 2020 production averaged 193 MMcf per day, a 15% decrease year-over-year.

Canadian waterflood production averaged 7,675 BOE per day during the fourth quarter of 2020, approximately flat compared to the prior quarter and 10% lower than the same period in 2019. Full year 2020 production averaged 7,469 BOE per day, a 17% decrease year-over-year.

Summary of Average Daily Production[1]

	Three months ended December 31, 2020					Twelve months ended December 31, 2020				
	Williston Basin	Marcellus	Canadian Water-floods	Other[2]	Total	Williston Basin	Marcellus	Canadian Water-floods	Other[2]	Total
Light & medium oil (bbl/d)	-	-	3,167	25	**3,192**	-	-	3,233	43	**3,277**
Heavy oil (bbl/d)	-	-	4,189	28	**4,216**	-	-	3,866	35	**3,901**
Tight oil (bbl/d)	35,067	-	-	930	**35,997**	37,007	-	-	1,236	**38,243**
Total crude oil (bbl/d)	**35,067**	**-**	**7,356**	**982**	**43,405**	**37,007**	**-**	**7,100**	**1,314**	**45,421**
Natural gas liquids (bbl/d)	**5,119**	**-**	**44**	**627**	**5,790**	**4,918**	**-**	**54**	**661**	**5,633**
Conventional natural gas (Mcf/d)	-	-	1,654	8,727	**10,381**	-	-	1,892	10,421	**12,314**
Shale gas (Mcf/d)	35,644	175,346	-	922	**211,912**	31,200	193,002	-	1,342	**225,543**
Total natural gas (Mcf/d)	**35,644**	**175,346**	**1,654**	**9,649**	**222,293**	**31,200**	**193,002**	**1,892**	**11,763**	**237,857**
Total production (BOE/d)	**46,127**	**29,224**	**7,675**	**3,218**	**86,244**	**47,125**	**32,167**	**7,469**	**3,936**	**90,697**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and non-core properties in Canada.

Summary of Wells Drilled[1]

	Three months ended December 31, 2020				Twelve months ended December 31, 2020			
	Operated		Non-Operated		Operated		Non-Operated	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Williston Basin	-	-	1	0.4	19	18.8	11	3.0
Marcellus	-	-	23	1.6	-	-	70	4.8
Canadian Waterfloods	-	-	-	-	10	10.0	-	-
Other[2]	-	-	-	-	5	4.4	16	0.9
Total	**-**	**-**	**24**	**1.9**	**34**	**33.2**	**97**	**8.7**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and non-core properties in Canada.

Summary of Wells Brought On-Stream[1]

	Three months ended December 31, 2020				Twelve months ended December 31, 2020			
	Operated		Non-Operated		Operated		Non-Operated	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Williston Basin	4	4.0	7	1.6	22	20.0	15	3.9
Marcellus	-	-	19	1.2	-	-	54	2.2
Canadian Waterfloods	-	-	-	-	10	10.0	-	-
Other[2]	-	-	-	-	2	1.8	1	0.0
Total	**4**	**4.0**	**26**	**2.8**	**34**	**31.8**	**70**	**6.1**

(1) Table may not add due to rounding.
(2) Comprises DJ Basin and non-core properties in Canada.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE (ESG) UPDATE

Enerplus continued to make strong progress on its ESG initiatives in 2020. Based on preliminary estimates, the Company expects to have reduced its 2020 GHG emissions intensity by more than 20% compared to 2019, an improvement compared to its target reduction of 10%. The Company also reduced its 2020 freshwater use per well completion in North Dakota by 23% compared to 2019, an improvement compared to its target reduction of 15%. Enerplus is finalizing its 2021 environmental targets as it works towards its longer-term goals, including a 50% reduction in GHG emissions intensity by 2030 and a 50% reduction in freshwater use per well completion by 2025.

Enerplus is also on track to achieve its safety targets having delivered a company record in 2020 with a lost time injury frequency ("LTIF") of 0.08 injuries per 200,000 worker hours, a 66% improvement from 2019. Enerplus is targeting a 25% reduction in LTIF, on average, from 2020 to 2023, relative to its 2019 baseline of 0.24.

BRUIN ACQUISITION AND 2021 GUIDANCE

On January 25, 2021, Enerplus announced that it had entered into a definitive agreement to acquire the equity interest of Bruin, a pure play Williston Basin private company, for total cash consideration of US$465 million, with no assumption of debt and subject to customary closing conditions and purchase price adjustments (the "Bruin Acquisition"). The Bruin Acquisition includes approximately 24,000 BOE per day of existing production and is expected to close in early March 2021. In connection with the Bruin Acquisition, Enerplus entered into a binding commitment letter for a new three-year senior unsecured US$400 million term facility to be fully drawn down on the closing date of the Bruin Acquisition to pay for a portion of the purchase price. Enerplus intends to fund the remaining portion of the purchase price with net proceeds from a $132.3 million bought deal equity financing, which was completed on February 3, 2021.

Assuming completion of the Bruin Acquisition and a ten-month contribution from the Bruin assets to Enerplus' 2021 results, Enerplus expects to deliver 2021 production of 103,500 to 108,500 BOE per day, including 63,000 to 67,000 barrels per day of liquids. Capital spending in 2021 is expected to be $335 to $385 million.

Pro forma for the Bruin Acquisition, the Company expects to realize a Bakken oil price differential of $3.25 per barrel below WTI in 2021 assuming the Dakota Access Pipeline ("DAPL") continues to operate. For the Marcellus, Enerplus expects to realize a natural gas price differential of US$0.55 per Mcf below NYMEX in 2021.

Detailed guidance for 2021 will be provided following closing of the Bruin Acquisition.

PRICE RISK MANAGEMENT UPDATE

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

Enerplus' Financial Commodity Hedging Contracts (As at February 18, 2021)

	WTI Crude Oil (US$/bbl)[(1)]				NYMEX Natural Gas (US$/Mcf)	
	Jan 1, 2021 – Mar 31, 2021	**Apr 1, 2021- Jun 30, 2021**	**Jul 1, 2021 - Dec 31, 2021**	**Jan 1 ,2022 - Dec 31, 2022**	**Mar 1, 2021 - Mar 31, 2021**	**Apr 1, 2021 - Oct 31, 2021**
Swaps						
Volume (bbls/d or Mcf/d)	5,000	-	-	-	60,000	60,000
Sold Swaps	$ 45.55	-	-	-	$3.16	$ 2.90
Three Way Collars						
Volume (bbls/d or Mcf/d)	15,000	20,000	23,000	17,000	-	40,000
Sold Puts	$ 32.00	$ 32.00	$ 36.39	$ 40.00	-	$ 2.15
Purchased Puts	$ 40.53	$ 40.90	$ 46.39	$ 50.39	-	$ 2.75
Sold Calls	$ 50.29	$ 50.72	$ 56.70	$ 57.91	-	$ 3.25

(1) The total average deferred premium spent on these hedges is US$0.80/bbl from January 1, 2021 to December 31, 2021 and US$1.50/bbl from January 1, 2022 to December 31, 2022.

Bruin's latest commodity hedging positions are provided below, which Enerplus will assume upon close of the Bruin Acquisition.

Bruin's Financial Commodity Hedging Contracts (As at February 18, 2021)

	WTI Crude Oil (US$/bbl)[(1)(2)]			
	Mar 1, 2021 - Dec 31, 2021	**Jan 1, 2022 - Dec 31, 2022**	**Jan 1, 2023 - Oct 31, 2023**	**Nov 1, 2023- Dec 31, 2023**
Swaps				
Volume (bbls/d)	9,000	3,900	250	-
Sold Swaps	$ 42.38	$ 42.38	$ 42.10	-
Collars				
Volume (bbls/d)	-	-	2,000	2,000
Purchased Puts	-	-	$ 5.00	$ 5.00
Sold Calls	-	-	$ 75.00	$ 75.00

(1) Transactions with a common term have been aggregated and presented at weighted average prices and volumes.
(2) Upon close of the Bruin Acquisition, these hedges will be recorded at fair value on the Consolidated Balance Sheets. Realized and unrealized gains and losses on the acquired hedges will be recorded in the Consolidated Statement of Income/(Loss) and the Consolidated Balance Sheets, respectively, to reflect changes in WTI prices from the date of the close of the Bruin Acquisition.

SUMMARY FINANCIAL AND OPERATING RESULTS

SELECTED FINANCIAL RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2020	2019	2020	2019
Financial (CDN$, thousands, except ratios)				
Net Income/(Loss)	$ (204,167)	$ (429,143)	$ (923,367)	$ (259,720)
Adjusted Net Income[1]	22,149	34,365	19,758	243,160
Cash Flow from Operating Activities	96,079	188,492	446,365	694,240
Adjusted Funds Flow[1]	91,871	178,922	358,160	708,992
Dividends to Shareholders - Declared	6,677	6,656	26,698	27,688
Total Debt Net of Cash[1]	375,967	454,984	375,967	454,984
Capital Spending	52,414	99,389	291,468	618,910
Property and Land Acquisitions	2,061	6,126	10,121	24,406
Property Divestments	47	(316)	6,145	9,583
Net Debt to Adjusted Funds Flow Ratio[1]	1.0x	0.6x	1.0x	0.6x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ (0.92)	$ (1.93)	$ (4.15)	$ (1.12)
Net Income/(Loss) - Diluted	(0.92)	(1.93)	(4.15)	(1.12)
Weighted Average Number of Shares Outstanding (000's) - Basic	222,548	222,227	222,503	231,334
Weighted Average Number of Shares Outstanding (000's) - Diluted	222,548	222,227	222,503	231,334
Selected Financial Results per BOE[2][3]				
Crude Oil & Natural Gas Sales[4]	$ 30.60	$ 41.64	$ 27.82	$ 42.65
Royalties and Production Taxes	(7.67)	(10.93)	(7.12)	(10.88)
Commodity Derivative Instruments	3.12	0.07	3.95	0.42
Operating Expenses	(8.20)	(8.05)	(7.94)	(7.88)
Transportation Costs	(3.89)	(3.82)	(3.99)	(3.93)
General and Administrative Expenses	(1.46)	(1.34)	(1.35)	(1.32)
Cash Share-Based Compensation	(0.11)	0.01	0.04	(0.02)
Interest, Foreign Exchange and Other Expenses	(0.81)	(0.89)	(1.06)	(0.72)
Current Income Tax Recovery	—	1.41	0.44	0.91
Adjusted Funds Flow[1]	$ 11.58	$ 18.10	$ 10.79	$ 19.23

SELECTED OPERATING RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2020	2019	2020	2019
Average Daily Production[3]				
Crude Oil (bbls/day)	43,405	54,344	45,421	49,704
Natural Gas Liquids (bbls/day)	5,790	5,502	5,633	4,929
Natural Gas (Mcf/day)	222,293	285,537	237,857	278,451
Total (BOE/day)	86,244	107,436	90,697	101,042
% Crude Oil and Natural Gas Liquids	57%	56%	56%	54%
Average Selling Price[3][4]				
Crude Oil (per bbl)	$ 47.95	$ 67.23	$ 44.35	$ 68.98
Natural Gas Liquids (per bbl)	17.19	18.28	10.29	15.19
Natural Gas (per Mcf)	2.04	2.50	1.87	2.87
Net Wells Drilled	2	9	42	56

(1) These non-GAAP measures may not be directly comparable to similar measures presented by other entities. See "Non-GAAP Measures" section in this news release.
(2) Non-cash amounts have been excluded.
(3) Based on Company interest production volumes. See "Basis of Presentation" section in this news release.
(4) Before transportation costs, royalties and commodity derivative instruments.

INDEPENDENT RESERVES EVALUATION

All of the Company's reserves, including its U.S. reserves, have been evaluated in accordance with NI 51-101. Independent reserves evaluations have been conducted on properties comprising approximately 98% of the net present value (discounted at 10%, before tax, using January 1, 2021 forecast prices and costs described below) of the Company's total 2P reserves.

McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent petroleum consulting firm based in Calgary, Alberta, has evaluated properties which comprise approximately 86% of the net present value (discounted at 10%, before tax, using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants ("GLJ") and Sproule Associates Limited ("Sproule") as of January 1, 2021) of the Company's 2P reserves located in Canada and all of the reserves associated with the Company's properties located in North Dakota, Montana and Colorado. The Company has evaluated the remaining 14% 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 the Company's internal evaluation of these properties. Netherland, Sewell & Associates ("NSAI"), independent petroleum consultants based in Dallas, Texas, has evaluated all of the Company's reserves associated with the Company's properties in Pennsylvania. For consistency in the Company's reserves reporting, NSAI also used the average commodity price forecasts and inflation rates of McDaniel, GLJ and Sproule as of January 1, 2021 to prepare its report.

The following information sets out Enerplus' gross and net crude oil, NGLs and natural gas reserves volumes and the estimated net present values of future net revenues associated with such reserves as at December 31, 2020 using forecast price and cost cases, together with certain information, estimates and assumptions associated with such reserves estimates. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit associated with a property. It should be noted that tables may not add due to rounding. The following information does not give effect to the Bruin Acquisition.

Reserves Summary

Reserves Summary	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Gross								
Proved producing	5,884	15,052	51,508	72,444	8,123	17,279	568,258	178,156
Proved developed non-producing	93	-	2,970	3,063	326	-	3,918	4,043
Proved undeveloped	660	1,893	51,708	54,261	6,451	74	357,370	120,286
Total proved	6,637	16,946	106,186	129,769	14,900	17,353	929,546	302,485
Total probable	2,383	5,309	63,941	71,633	8,602	5,811	244,388	121,934
Proved plus Probable	**9,020**	**22,254**	**170,127**	**201,402**	**23,501**	**23,164**	**1,173,934**	**424,419**
Net								
Proved producing	4,894	13,076	41,481	59,451	6,629	17,945	456,831	145,209
Proved developed non-producing	77	-	2,397	2,474	260	-	3,194	3,266
Proved undeveloped	563	1,587	41,403	43,553	5,159	63	283,680	96,002
Total proved	5,534	14,663	85,281	105,477	12,048	18,008	743,705	244,478
Total probable	1,906	4,542	51,224	57,672	6,929	5,928	195,781	98,219
Proved plus Probable	**7,440**	**19,204**	**136,505**	**163,149**	**18,977**	**23,936**	**939,485**	**342,697**

Reserves Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2019 to December 31, 2020.

Proved Reserves - Gross Volumes (Forecast Prices)

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2019	7,770	20,121	112,812	140,703	14,327	24,242	933,737	314,693
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	-	-	12,111	12,111	1,636	-	76,643	26,521
Economic factors	(465)	(1,082)	(5,668)	(7,215)	(849)	(2,195)	(9,970)	(10,092)
Technical revisions	529	(666)	890	754	1,802	(824)	11,606	4,352
Production	(1,197)	(1,428)	(13,959)	(16,584)	(2,016)	(3,870)	(82,470)	(32,990)
Proved Reserves at Dec. 31, 2020	**6,637**	**16,946**	**106,186**	**129,769**	**14,900**	**17,353**	**929,546**	**302,485**

Probable Reserves - Gross Volumes (Forecast Prices)

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2019	2,788	6,470	68,240	77,498	8,396	7,395	233,613	126,061
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	-	-	6,454	6,454	698	-	38,538	13,576
Economic factors	11	(506)	(1,537)	(2,032)	(209)	(588)	(975)	(2,501)
Technical revisions	(416)	(655)	(9,216)	(10,287)	(284)	(997)	(26,788)	(15,202)
Production	-	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2020	**2,383**	**5,309**	**63,941**	**71,633**	**8,602**	**5,811**	**244,388**	**121,934**

Proved Plus Probable Reserves - Gross Volumes (Forecast Prices)

	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Tight Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Conventional Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2019	10,558	26,591	181,052	218,201	22,723	31,637	1,167,349	440,755
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	-	-	18,565	18,565	2,335	-	115,181	40,097
Economic factors	(454)	(1,589)	(7,205)	(9,248)	(1,058)	(2,783)	(10,946)	(12,593)
Technical revisions	113	(1,320)	(8,326)	(9,533)	1,518	(1,821)	(15,181)	(10,849)
Production	(1,197)	(1,428)	(13,959)	(16,584)	(2,016)	(3,870)	(82,470)	(32,990)
Proved Plus Probable Reserves at Dec. 31, 2020	**9,020**	**22,254**	**170,127**	**201,402**	**23,501**	**23,164**	**1,173,934**	**424,419**

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Future Development Costs

Changes in forecast FDC occur annually as a result of development activities, acquisition and divestment activities and capital cost estimates that reflect the evaluators' best estimate of the capital required to bring the proved and proved plus probable reserves on production. The aggregate of the exploration and development costs incurred in the most recent year and the change during the year in estimated FDC generally reflect the total finding and development costs related to reserves additions for that year.

The following is a summary of the estimated FDC required to bring the total proved and proved plus probable reserves on production:

Future Development Costs	Proved Reserves	Proved Plus Probable Reserves
($ millions)		
2021	258	260
2022	314	315
2023	321	344
2024	264	378
2025	34	303
2026	3	277
Remainder	3	6
Total FDC Undiscounted	1,197	1,883
Total FDC Discounted at 10%	989	1,431

F&D AND FD&A COSTS – *including FDC*

($ millions except for per BOE amounts)	2020	2019	2018	3 Year
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$291.4	$618.9	$593.8	$1,504.1
Net change in Future Development Costs	$(183.2)	$47.0	$309.1	$172.9
Gross Reserves additions (MMBOE)	16.7	51.0	65.7	133.4
F&D costs ($/BOE)	**$6.50**	**$13.05**	**$13.74**	**$12.57**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$295.4	$633.7	$612.7	$1,541.8
Net change in Future Development Costs	$(183.2)	$44.0	$308.1	$168.8
Gross Reserves additions (MMBOE)	16.7	49.7	64.1	130.4
FD&A costs ($/BOE)	**$6.74**	**$13.63**	**$14.37**	**$13.12**
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$291.4	$618.9	$593.8	$1,504.1
Net change in Future Development Costs	$(150.5)	$2.4	$309.3	$161.2
Gross Reserves additions (MMBOE)	20.8	54.6	54.1	129.5
F&D costs ($/BOE)	**$6.78**	**$11.37**	**$16.69**	**$12.86**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$295.4	$633.7	$612.7	$1,541.8
Net change in Future Development Costs	$(150.5)	$(0.5)	$308.3	$157.3
Gross Reserves additions (MMBOE)	20.8	53.6	52.9	127.2
FD&A costs ($/BOE)	**$6.97**	**$11.82**	**$17.42**	**$13.35**
Proved Developed Producing Reserves				
Finding & Development Costs				
Capital Expenditures	$291.4	$618.9	$593.8	$1,504.1
Gross Reserves additions (MMBOE)	11.0	38.8	45.4	95.1
F&D costs ($/BOE)	**$26.51**	**$15.97**	**$13.08**	**$15.81**

Forecast Price Assumptions

The forecast price and cost case assumes no legislative or regulatory amendments, and includes the effects of inflation. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2021 (utilized by McDaniel, NSAI and by the Company in its internal evaluations for consistency in the Company's reserves reporting), and the following inflation and exchange rate assumptions.

	WTI Crude Oil(1) US$/bbl	Light Crude Oil(2) Edmonton CDN$/bbl	Alberta Heavy Crude Oil(3) CDN$/bbl	U.S. Henry Hub Gas Price US$/MMBtu	Exchange Rate US$/CDN$	Inflation Rate %/year
2021	47.17	55.76	39.87	2.83	0.768	0.0
2022	50.17	59.89	43.20	2.87	0.765	1.3
2023	53.17	63.48	46.86	2.90	0.763	2.0
2024	54.97	65.76	48.67	2.96	0.763	2.0
2025	56.07	67.13	49.65	3.02	0.763	2.0
2026	57.19	68.53	50.65	3.08	0.763	2.0
2027	58.34	69.95	51.67	3.14	0.763	2.0
2028	59.50	71.40	52.71	3.20	0.763	2.0
2029	60.69	72.88	53.76	3.26	0.763	2.0
2030	61.91	74.34	54.84	3.33	0.763	2.0
2031	63.15	75.83	55.94	3.39	0.763	2.0
2032	64.41	77.34	57.05	3.46	0.763	2.0
2033	65.70	78.89	58.20	3.53	0.763	2.0
2034	67.01	80.47	59.36	3.60	0.763	2.0
2035	68.35	82.08	60.55	3.67	0.763	2.0
Thereafter	(4)	(4)	(4)	(4)	0.763	2.0

(1) West Texas Intermediate at Cushing, Oklahoma 40 degree API / 0.5% Sulphur.
(2) Edmonton Light Sweet 40 degree API, 0.3% Sulphur.
(3) Heavy Crude Oil 12 degree API at Hardisty, Alberta (after deducting blending costs to reach pipeline quality).
(4) Escalation is approximately 2% per year thereafter.

Net Present Value of Future Production Revenue

The following table provides an estimate of the net present value of Enerplus' future production revenue after deduction of royalties, estimated future capital and operating expenditures, before income taxes. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves.

Net Present Value of Future Production Revenue – Forecast Prices and Costs *(before tax)*

Reserves at December 31, 2020, ($ Millions, discounted at)	**0%**	**5%**	**10%**	**15%**
Proved developed producing	1,855	1,597	1,353	1,169
Proved developed non-producing	55	47	39	33
Proved undeveloped	1,118	700	449	290
Total Proved	3,028	2,344	1,841	1,492
Probable	1,990	1,171	755	526
Total Proved Plus Probable Reserves (before tax)	5,019	3,515	2,596	2,018

Contingent Resources

The following table provides a breakdown of the economic, unrisked best estimate contingent resources associated with a portion of Enerplus' Fort Berthold and Marcellus assets as at December 31, 2020. These contingent resources are economic using the average of the three independent petroleum consulting firms' price forecasts (McDaniel, GLJ and Sproule) as of January 1, 2021, use established technologies and are all classified in the "development pending" maturity sub-class. However, there is uncertainty that it will be commercially viable to produce any portion of the resources.

The evaluation of contingent resources associated with Enerplus' properties and leases at Fort Berthold were conducted by Enerplus and audited by McDaniel. NSAI evaluated 100% of Enerplus' Marcellus shale gas assets in the U.S., including the estimate of contingent resources.

Please see Enerplus' Annual Information Form ("AIF") – Appendix A for additional disclosures related to Enerplus' contingent resources as at December 31, 2020. The AIF is available at www.enerplus.com as well as on the Company's SEDAR profile at www.sedar.com.

Development Pending Contingent Resources	Unrisked "Best Estimate" Contingent Resources		Contingent Resources Net Drilling Locations
Fort Berthold – Bakken/Three Forks Tight oil wells	72.0	MMBOE	136.3
Marcellus - Shale gas	621.2	Bcf	32.6
Total	**175.5**	**MMBOE**	**168.9**

LIVE CONFERENCE CALL

Enerplus plans to hold a conference call hosted by Ian C. Dundas, President and CEO, today, February 19, 2021 at 9:00 a.m. MT (11:00 a.m. ET) to discuss these results. Details of the conference call are as follows:

Date: Friday, February 19, 2021
Time: 9:00 am MT/11:00 am ET
Dial-In: 416-764-8688
1-888-390-0546 (toll free)
Conference ID: 87527222
Audiocast: https://produceredition.webcasts.com/starthere.jsp?ei=1418451&tp_key=a39387ec4a

To ensure timely participation in the conference call, callers are encouraged to dial in 15 minutes prior to the start time to register for the event. A telephone replay will be available for 30 days following the conference call and can be accessed at the following numbers:

Dial-In: 416-764-8677
1-888-390-0541 (toll free)
Passcode: 527222 #

Electronic copies of Enerplus' 2020 MD&A and Financial Statements, along with other public information including investor presentations, are available on the Company's website at www.enerplus.com. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

Follow @EnerplusCorp on Twitter at https://twitter.com/EnerplusCorp.

INFORMATION REGARDING RESERVES, RESOURCES AND OPERATIONAL INFORMATION

Currency and Accounting Principles

All amounts in this news release are stated in Canadian dollars unless otherwise specified. All financial information in this news release has been prepared and presented in accordance with U.S. GAAP, except as noted below under "Non-GAAP Measures".

Barrels of Oil Equivalent

This news release also contains references to "BOE" (barrels of oil equivalent), "MBOE" (one thousand barrels of oil equivalent), and "MMBOE" (one million barrels of oil equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs. BOE, MBOE and MMBOE may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading.

Presentation of Production and Reserves Information

All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest with the exception of production utilized to calculate reserves replacement ratios which are on a working interest basis. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on "gross reserves" using forecast prices and costs. "Gross reserves" (as defined in NI 51-101), are Enerplus' working interest before deduction of any royalties. Enerplus' oil and gas reserves statement for the year ended December 31, 2020, which will include complete *disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained within our Annual Information Form (AIF) for the year ended December 31, 2020 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. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and as part of our Form 40-F on EDGAR concurrently with this news release for more complete disclosure on our operations.*

All references to "liquids" in this news release include light and medium crude oil, heavy oil and tight oil (all together referred to as "crude oil") and natural gas liquids on a combined basis.

Contingent Resources Estimates

This news release contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as ultimate recovery rates, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. All of our contingent resources estimates are economic using established technologies and based on the average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2021. Enerplus expects to develop these contingent resources in the coming years however it is too early in their development for all of these resources to be classified as reserves at this time. A portion of these contingent resources are part of continuous development by the Company and are categorized as contingent resources primarily due to development timelines that go beyond what is already assigned as undeveloped reserves. There is uncertainty that Enerplus will produce any portion of the volumes currently classified as "contingent resources". "Development pending contingent resources" refer to a "contingent resources" project maturity sub-class for a particular project where resolution of the final conditions for development are being actively pursued (there is a high chance of development) and the project is expected to be developed in a reasonable timeframe. The "contingent resources" estimates contained herein are presented as the "best estimate" of the quantity that will actually be recovered, effective as of December 31, 2020. A "best estimate" of contingent resources means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

For additional information regarding the primary contingencies which currently prevent the classification of Enerplus' disclosed "contingent resources" associated with Enerplus' Marcellus shale gas properties and Fort Berthold properties as reserves and the positive and negative factors relevant to the "contingent resources" estimates, see Appendix A to Enerplus' AIF, a copy of which is available under Enerplus' SEDAR profile at www.sedar.com, and Enerplus' Form 40-F, a copy of which is available under Enerplus' EDGAR profile at www.sec.gov.

F&D and FD&A Costs

F&D costs presented in this news release are calculated (i) in the case of F&D costs for proved developed producing reserves, by dividing the sum of the exploration and development costs incurred in the year, by the additions to proved developed producing reserves in the year, (ii) 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 (iii) 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 Canadian dollars per working interest BOE unless otherwise specified.

FD&A costs presented in this news release 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 Canadian dollars per working interest BOE unless otherwise specified.

NOTICE TO U.S. READERS

The oil and natural gas reserves information contained in this news release has generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. Reserves categories such as "proved reserves" and "probable reserves" may be defined differently under Canadian requirements than the definitions contained in the United States Securities and Exchange Commission (the "SEC") rules. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross (or, as noted above with respect to production information, "company interest") volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Canadian disclosure requirements require that forecasted commodity prices be used for reserves evaluations, while the SEC mandates the use of an average of first day of the month price for the 12 months prior to the end of the reporting period. Additionally, the SEC prohibits disclosure of oil and gas resources in SEC filings, whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not be construed *as reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see "Contingent Resources Estimates" above.*

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("forward-looking information"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "believes" and "plans" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this news release contains forward-looking information pertaining to the following: the continued uncertainty regarding timing and impact of the COVID-19 pandemic; anticipated completion, including timing, of the Bruin Acquisition and its expected impacted of on Enerplus' operations and financial results; expected 2021 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 adjusted funds flow; the results from our drilling program, timing of related production, and ultimate well recoveries; oil and natural gas prices and differentials and our commodity risk management programs in 2021 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 and non-cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2021, net debt to adjusted funds-flow ratio, financial capacity and liquidity and capital resources to fund capital spending and working capital requirements; and our ESG initiatives, including GHG emissions and freshwater reduction targets.

The forward-looking information contained in this news release reflects several material factors, expectations and assumptions including, without limitation: closing of the Bruin Acquisition substantially on the terms and timelines previously announced; that we will conduct our operations and achieve results of operations as anticipated; 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; estimated commodity price, differentials and cost assumptions, including continued operation of DAPL; 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; the availability of technology and processes to achieve environmental targets. In addition, Enerplus' 2021 outlook contained in this news release is based on the following, as well as closing of the Bruin Acquisition in early March 2021: a WTI price of US$55.00/bbl, a NYMEX price of US$3.00/Mcf, a Bakken crude oil price differential of US$3.25/bbl below WTI and a USD/CDN exchange rate of 1.27. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this news release is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or further volatility in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; failure to complete the Bruin Acquisition in accordance with its terms or at all and failure to realize the anticipated benefits of the Bruin Acquisition; 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; 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; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in Enerplus' 2020 MD&A and in our other public filings).

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

NON-GAAP MEASURES

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

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