NEWS RELEASE

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Enerplus Announces Fourth Quarter and Full Year 2019 Financial and Operating Results, 2019 Year End Reserves and ESG Targets

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' 2019 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 2019 cash flow from operating activities of $188.5 million and adjusted funds flow of $178.9 million. Enerplus reported a fourth quarter 2019 net loss of $429.1 million, or $(1.93) per share. The Company recognized a $451.1 million non-cash goodwill impairment related to its Canadian reporting unit in the quarter. Excluding the goodwill impairment and certain other non-cash or non-recurring items, fourth quarter 2019 adjusted net income was $34.4 million, or $0.15 per share.

Full year 2019 cash flow from operating activities was $694.2 million and adjusted funds flow was $709.0 million. The Company reported a full year 2019 net loss of $259.7 million, or $(1.12) per share. Excluding the goodwill impairment and certain other non-cash or non-recurring items, full year 2019 adjusted net income was $243.2 million, or $1.05 per share.

FULL YEAR 2019 SUMMARY

- Total production increased 8% (14% per share) year-over-year to 101,042 BOE per day
- Liquids production increased 9% (15% per share) year-over-year to 54,633 barrels per day
- Adjusted funds flow was $709.0 million, which exceeded capital spending of $618.9 million, generating free cash flow of $90.1 million
- Returned $206.5 million to shareholders through share repurchases and dividends
- Maintained strong financial flexibility; ended the year with a net debt to adjusted funds flow ratio of 0.6 times
- Achieved 139% proved plus probable ("2P") reserves replacement, including 206% 2P reserves replacement in North Dakota
- 2P reserves increased 3% (11% per share) year-over-year

"We delivered strong results in 2019 having generated double-digit production per share growth and returning over $200 million to shareholders," stated Ian C. Dundas, President and Chief Executive Officer. "We have positioned Enerplus to be resilient through commodity price cycles with our strong balance sheet, profitable growth plan underpinned by financial returns and focus on generating free cash flow. In addition, we believe that our commitment to environmental, social and governance initiatives will further support long-term value creation."

FOURTH QUARTER 2019 REVIEW

Total production for the fourth quarter of 2019 was 107,436 BOE per day, exceeding the Company's guidance range of 103,000 to 107,000 BOE per day, and a 10% increase from the same period in 2018. Crude oil and natural gas liquids production was 59,846 barrels per day in the fourth quarter, achieving the high end of the Company's guidance range of 58,000 to 60,000 barrels per day, and a 10% increase from the same period in 2018. The production increase was driven by higher North Dakota and Marcellus volumes.

Adjusted funds flow was $178.9 million in the fourth quarter, 17% lower than the same period in 2018 primarily due to an increase in operating expenses and a lower Alternative Minimum Tax (“AMT”) refund of $13.9 million in the fourth quarter of 2019, compared to $27.3 million in the fourth quarter of 2018.

Enerplus recorded a net loss of $429.1 million in the fourth quarter compared to net income of $249.3 million in the same period in 2018. Earnings decreased from the fourth quarter of 2018 primarily due to a $451.1 million non-cash goodwill impairment related to the Company’s Canadian reporting unit as a result of the cumulative impact of Canadian asset divestments, the shut-in of uneconomic natural gas production in Tommy Lakes and lower forecasted commodity prices. Earnings were further impacted by a $28.8 million loss on commodity derivative instruments in the fourth quarter of 2019 compared to a $253.7 million gain in the same period in 2018. Excluding the goodwill impairment and certain other non-cash or non-recurring items, fourth quarter adjusted net income was $34.4 million, compared to $102.2 million in the same period in 2018. The reduction in adjusted net income was primarily due to higher operating expenses and a realized foreign exchange loss in the fourth quarter of 2019.

Enerplus’ fourth quarter 2019 Bakken crude oil price differential was US$4.40 per barrel below WTI, compared to US$5.60 per barrel below WTI for the same period in 2018. Enerplus’ fourth quarter Marcellus natural gas price differential was US$0.63 per Mcf below NYMEX, compared to US$0.34 per Mcf below NYMEX for the same period in 2018.

Operating expenses in the fourth quarter increased to $8.05 per BOE, compared to $6.99 per BOE in the same period in 2018, as a result of higher fluid handling costs due to increased crude oil volumes and additional well servicing activity. Cash general and administrative (“G&A”) expenses in the fourth quarter decreased to $1.34 per BOE, compared to $1.40 per BOE in the same period of 2018, primarily due to higher production.

Exploration and development capital spending totaled $99.4 million in the fourth quarter of 2019. The Company also spent $23.7 million repurchasing 2.7 million shares and paid $6.7 million in dividends during the fourth quarter.

Enerplus ended the fourth quarter of 2019 with total debt net of cash of $455.0 million and was undrawn on its US$600 million senior unsecured bank credit facility. The Company’s net debt to adjusted funds flow ratio was 0.6 times at quarter-end.

FULL YEAR 2019 REVIEW

Total production for 2019 was 101,042 BOE per day, an 8% (14% per share) increase from 2018. Crude oil and natural gas liquids production was 54,633 barrels per day in 2019, a 9% (15% per share) increase from 2018.

Adjusted funds flow was $709.0 million in 2019, 6% lower than 2018 primarily due to lower benchmark commodity prices and higher operating expenses in 2019.

Enerplus recorded a net loss of $259.7 million in 2019 compared to net income of $378.3 million in 2018. Earnings decreased from 2018 primarily due to a $451.1 million non-cash Canadian goodwill impairment and a loss on commodity derivative instruments of $66.1 million, compared to a gain of $88.2 million recorded in 2018. Excluding the goodwill impairment and certain other non-cash or non-recurring items, 2019 adjusted net income was $243.2 million, compared to $344.8 million in 2018. The reduction in adjusted net income was primarily due to lower benchmark commodity prices and higher operating expenses in 2019.

Enerplus’ 2019 Bakken crude oil price differential was US$3.61 per barrel below WTI, compared to US$3.78 per barrel below WTI in 2018. Enerplus’ 2019 Marcellus natural gas price differential was US$0.39 per Mcf below NYMEX, compared to US$0.43 per Mcf below NYMEX in 2018.

Operating expenses in 2019 were $7.88 per BOE, compared to $7.00 per BOE in 2018. The increase was largely due to additional well servicing activity and higher fluid handling and gas processing costs in North Dakota. Cash G&A expenses in 2019 were $1.32 per BOE, compared to $1.47 per BOE in 2018. The lower cash G&A expenses per BOE were primarily due to higher production levels in 2019 compared to 2018.

Exploration and development capital spending totaled $618.9 million in 2019, below the Company’s capital budget guidance of $625 million.

The Company spent $178.8 million repurchasing 18.2 million shares and paid $27.7 million in dividends in 2019. Subsequent to year end and up to February 20, 2020, the Company repurchased 0.3 million shares for total consideration of $2.5 million. Since initiating its share repurchase program in the third quarter of 2018, Enerplus has repurchased 24.5 million shares, representing approximately 10% of shares outstanding.

2019 YEAR END RESERVES SUMMARY

- Replaced 139% of 2019 production, adding 51.0 MMBOE (57% crude oil) of 2P reserves (including revisions and economic factors).
- Material reserves growth was realized in North Dakota where the Company replaced 206% of 2019 production, adding 34.2 MMBOE of 2P reserves (including revisions and economic factors).
- Total 2P reserves were 440.8 MMBOE at year end 2019, representing a 3% (11% per share) increase from year end 2018
- F&D costs were $15.97 per BOE for proved developed producing ("PDP") reserves, $11.37 per BOE for proved reserves, and $13.05 per BOE for 2P reserves, including future development costs ("FDC").
- Finding, development and acquisition ("FD&A") costs were $11.82 per BOE for proved reserves and $13.63 per BOE for 2P reserves, including FDC.
- 2P reserves were comprised of 50% crude oil, 5% natural gas liquids, and 45% natural gas at year end 2019.

ASSET ACTIVITY

Williston Basin production averaged 54,113 BOE per day (82% crude oil) during the fourth quarter of 2019, 1% lower than the prior quarter and 14% higher than the same period in 2018. Fourth quarter Williston Basin production was comprised of 50,872 BOE per day in North Dakota and 3,241 BOE per day in Montana. Full year 2019 production from the Williston Basin averaged 48,745 BOE per day, a 13% increase year-over-year. In the fourth quarter, the Company drilled 12 gross operated wells (61% average working interest) in North Dakota. No operated wells were brought on production in the fourth quarter.

Marcellus natural gas production averaged 233 MMcf per day during the fourth quarter of 2019, 2% higher than the prior quarter and 10% higher than the same period in 2018. Full year 2019 production averaged 227 MMcf per day, a 9% increase year-over-year. In the fourth quarter, the Company participated in drilling 13 gross non-operated wells (2% average working interest) with five gross non-operated wells (28% average working interest) brought on production.

Canadian waterflood production averaged 8,580 BOE per day (93% crude oil) during the fourth quarter of 2019, 6% lower than the prior quarter and 12% lower than the same period in 2018. Full year 2019 production averaged 9,083 BOE per day, an 8% decrease year-over-year primarily due to the sale of assets in 2019 and production declines.

Average Daily Production(1)

	Three months ended December 31, 2019				Twelve months ended December 31, 2019			
	Crude Oil (Mbbl/d)	NGL (Mbbl/d)	Natural gas (MMcf/d)	Total (MBOE/d)	Crude Oil (Mbbl/d)	NGL (Mbbl/d)	Natural gas (MMcf/d)	Total (MBOE/d)
Williston Basin	44.4	4.6	30.4	54.1	40.1	4.0	27.8	48.7
Marcellus	-	-	232.7	38.8	-	-	226.7	37.8
Canadian Waterfloods	8.0	0.1	2.9	8.6	8.4	0.1	3.4	9.1
DJ Basin	1.8	0.1	0.7	1.9	1.0	0.1	0.2	1.0
Other(2)	0.1	0.7	18.8	4.0	0.2	0.8	20.3	4.4
Total	**54.3**	**5.5**	**285.5**	**107.4**	**49.7**	**4.9**	**278.5**	**101.0**

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

Summary of Wells Drilled(1)

	Three months ended December 31, 2019				Twelve months ended December 31, 2019			
	Operated		Non-Operated		Operated		Non-Operated	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Williston Basin	12	7.3	4	1.0	55	44.6	11	3.7
Marcellus	-	-	13	0.3	-	-	38	1.4
Canadian Waterfloods	-	-	-	-	1	1.0	-	-
DJ Basin	-	-	-	-	5	4.4	-	-
Other(2)	-	-	-	-	-	-	2	0.5
Total	**12**	**7.3**	**17**	**1.3**	**61**	**50.0**	**51**	**5.7**

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

Summary of Wells Brought On-Stream(1)

	Three months ended December 31, 2019				Twelve months ended December 31, 2019			
	Operated		Non-Operated		Operated		Non-Operated	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Williston Basin	-	-	4	1.6	40	34.3	9	3.6
Marcellus	-	-	5	1.4	-	-	45	5.7
Canadian Waterfloods	-	-	-	-	1	1.0	-	-
DJ Basin	-	-	-	-	5	4.4	-	-
Other(2)	-	-	-	-	-	-	2	0.5
Total	**-**	**-**	**9**	**3.0**	**46**	**39.7**	**56**	**9.8**

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

ENVIRONMENTAL, SOCIAL AND GOVERNANCE (ESG) – GREENHOUSE GAS EMISSIONS AND WATER TARGETS

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 greenhouse gas (GHG) emissions are becoming increasingly stringent, requiring businesses to adapt to support long-term value creation. As part of Enerplus' continued integration of ESG issues into its strategy and operations, the Company has established targets for reducing GHG emissions intensity and freshwater use.

Greenhouse Gas Emissions
Using 2019 as a baseline, Enerplus is targeting a 10% reduction of its GHG emissions per barrel of oil equivalent in 2020. Infrastructure expansion is expected to support the Company's efforts to reduce levels of flared natural gas in North Dakota in 2020, helping it reach its GHG emissions intensity reduction target. The Company is evaluating additional operational changes and aims to identify technologies and opportunities to achieve further emissions intensity reductions beyond 2020.

Enerplus' 2020 target addresses scope 1 and 2 emissions. Scope 1 emissions are direct emissions from owned and operated facilities. Scope 2 emissions are indirect emissions from the generation of purchased energy for the Company's owned and operated facilities.

Water Management
The vast majority (approximately 80% in 2018) of the water used in Enerplus' operations is reused. As Enerplus aims to further improve its water use efficiency, it has established a target to reduce its freshwater use per well completion in North Dakota by 15%, on average, in 2020, compared to 2019, by reusing produced water in its fracturing operations.

Other ESG Focus Areas
In addition to GHG emissions and water management, Enerplus has identified culture, stakeholder engagement, health & safety, and board expertise & engagement as material ESG focus areas. Enerplus believes that the continued integration of these focus areas into its strategy and operations will enhance long-term business resilience. Enerplus' ESG initiatives have oversight by the Board of Directors with each material focus area mapped to the applicable board subcommittee including the Compensation and Human Resources Committee, the Safety and Social Responsibility Committee and the Corporate Governance and Nominating Committee. A copy of Enerplus' ESG presentation is available on the Company's website at www.enerplus.com/investors/presentations-events.cfm.

BOARD CHAIR APPOINTMENT

Enerplus today announced that Elliott Pew will be stepping down as Board Chair effective May 7, 2020 at the Company's annual meeting. Hilary Foulkes, a director of Enerplus since 2014 and currently the Chair of the Corporate Governance & Nominating Committee, has been appointed as the new Board Chair upon Mr. Pew stepping down. Mr. Pew has served as Board Chair since 2014 and is stepping down as part of the board's succession planning and focus on strong continuity. Mr. Pew will continue with Enerplus as an independent director.

"On behalf of the Board, I would like to thank Elliott for his dedication and leadership," said Mr. Dundas. "And I look forward to his continued contributions as a board member. I am also excited to welcome Hilary as Chair," continued Dundas. "Her commitment and experience during her tenure as a director have been valuable to our company and Enerplus will continue to benefit from these strengths in her new expanded role as Board Chair."

PRICE RISK MANAGEMENT UPDATE

Enerplus has approximately 61% of its 2020 forecasted net crude oil production protected (based on the guidance midpoint). The Company has used swaps, put spreads and three-way collar structures to hedge crude oil providing downside protection, while retaining meaningful exposure to higher crude oil prices.

Commodity Hedging Detail (As at February 20, 2020)

	WTI Crude Oil (US$/bbl)[1]				
	Jan 1 – Jan 31, 2020	**Feb 1 – Mar 31, 2020**	**Apr 1 – Jun 30, 2020**	**Jul 1 – Sep 30, 2020**	**Oct 1 – Dec 31, 2020**
Swaps					
Volume (bbls/d)	5,000	10,000	12,000	2,000	-
Sold Swaps	$57.05	$54.56	$55.23	$57.18	-
Put Spreads					
Volume (bbls/d)	16,000	16,000	16,000	16,000	16,000
Sold Puts	$46.88	$46.88	$46.88	$46.88	$46.88
Purchased Puts	$57.50	$57.50	$57.50	$57.50	$57.50
Three Way Collars					
Volume (bbls/d)	-	-	-	5,000	5,000
Sold Puts	-	-	-	$48.00	$48.00
Purchased Puts	-	-	-	$56.25	$56.25
Sold Calls	-	-	-	$65.00	$65.00

(1) The total average deferred premium on outstanding 2020 hedges is US$1.69/bbl from January 1, 2020 to December 31, 2020.

2020 GUIDANCE

Enerplus' previously announced and unchanged 2020 guidance is provided below.

Capital spending	$520 to $570 million
Average annual production	96,000 – 100,000 BOE/d
Average annual crude oil and natural gas liquids production	57,000 – 60,000 BOE/d
Average royalty and production tax rate	26%
Operating expense	$8.50/BOE
Transportation expense	$4.00/BOE
Cash G&A expense	$1.50/BOE

2020 Differential/Basis Outlook[1]

U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(5.00)/bbl
Marcellus basis (compared to NYMEX natural gas)	US$(0.45)/Mcf

(1) Excluding transportation costs.

SELECTED FINANCIAL RESULTS	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Financial (CDN$, thousands, except ratios)				
Net Income/(Loss)	$ (429,143)	$ 249,315	$ (259,720)	$ 378,279
Adjusted Net Income[4]	34,365	102,167	243,160	344,813
Cash Flow from Operating Activities	188,492	221,619	694,240	738,784
Adjusted Funds Flow[4]	178,922	214,285	708,992	753,506
Dividends to Shareholders - Declared	6,656	7,234	27,688	29,256
Total Debt Net of Cash[4]	454,984	333,523	454,984	333,523
Capital Spending	99,389	72,058	618,910	593,876
Property and Land Acquisitions	6,126	9,474	24,406	25,840
Property Divestments	(316)	886	9,583	6,912
Net Debt to Adjusted Funds Flow Ratio[4]	0.6x	0.4x	0.6x	0.4x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ (1.93)	$ 1.03	$ (1.12)	$ 1.55
Net Income/(Loss) - Diluted	(1.93)	1.02	(1.12)	1.53
Weighted Average Number of Shares Outstanding (000's) - Basic	222,227	242,344	231,334	244,076
Weighted Average Number of Shares Outstanding (000's) - Diluted	222,227	245,242	231,334	247,261
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 41.64	$ 45.43	$ 42.65	$ 47.35
Royalties and Production Taxes	(10.93)	(11.58)	(10.88)	(11.92)
Commodity Derivative Instruments	0.07	(0.31)	0.42	(1.05)
Cash Operating Expenses	(8.05)	(6.99)	(7.88)	(7.00)
Transportation Costs	(3.82)	(3.71)	(3.93)	(3.63)
General and Administrative Expenses	(1.34)	(1.40)	(1.32)	(1.47)
Cash Share-Based Compensation	0.01	0.23	(0.02)	(0.01)
Interest, Foreign Exchange and Other Expenses	(0.89)	(0.90)	(0.72)	(0.92)
Current Income Tax Recovery	1.41	3.03	0.91	0.80
Adjusted Funds Flow[4]	$ 18.10	$ 23.80	$ 19.23	$ 22.15

SELECTED OPERATING RESULTS	Three months ended December 31, 2019	Three months ended December 31, 2018	Twelve months ended December 31, 2019	Twelve months ended December 31, 2018
Average Daily Production[2]				
Crude Oil (bbls/day)	54,344	49,968	49,704	45,424
Natural Gas Liquids (bbls/day)	5,502	4,483	4,929	4,486
Natural Gas (Mcf/day)	285,537	260,453	278,451	259,837
Total (BOE/day)	107,436	97,860	101,042	93,216
% Crude Oil and Natural Gas Liquids	56%	56%	54%	54%
Average Selling Price[2][3]				
Crude Oil (per bbl)	$ 67.23	$ 64.18	$ 68.98	$ 74.59
Natural Gas Liquids (per bbl)	18.28	26.72	15.19	28.31
Natural Gas (per Mcf)	2.50	4.28	2.87	3.42
Net Wells Drilled	9	12	56	61

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

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 97% of the net present value (discounted at 10%, before tax, using January 1, 2020 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 78% 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, 2020) 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 22% 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, 2020 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, 2019 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.

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	6,947	17,046	60,938	84,930	8,526	22,808	617,357	200,150
Proved developed non-producing	163	-	271	434	84	1,347	5,999	1,742
Proved undeveloped	660	3,075	51,603	55,338	5,717	88	310,381	112,801
Total proved	7,770	20,121	112,812	140,703	14,327	24,242	933,737	314,693
Total probable	2,788	6,470	68,240	77,498	8,396	7,395	233,613	126,061
Proved plus Probable	10,558	26,591	181,052	218,201	22,723	31,637	1,167,349	440,755
Net								
Proved producing	5,690	14,224	48,927	68,840	6,965	23,529	495,517	162,313
Proved developed non-producing	138	-	221	359	62	1,270	4,808	1,434
Proved undeveloped	557	2,558	41,309	44,424	4,575	73	246,155	90,038
Total proved	6,385	16,782	90,457	113,623	11,602	24,872	746,480	253,785
Total probable	2,160	5,298	54,576	62,034	6,758	7,467	186,702	101,154
Proved plus Probable	8,545	22,079	145,033	175,657	18,361	32,339	933,182	354,938

Reserves Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2018 to December 31, 2019.

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, 2018	9,637	21,181	106,530	137,347	13,783	31,007	849,063	297,809
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(982)	-	-	(982)	(18)	(319)	-	(1,053)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	388	-	21,731	22,119	2,340	741	88,893	39,399
Economic factors	(18)	(115)	(958)	(1,091)	(75)	(212)	(4,376)	(1,931)
Technical revisions	165	778	465	1,408	46	1,050	93,164	17,156
Production	(1,420)	(1,722)	(14,957)	(18,098)	(1,749)	(8,026)	(93,008)	(36,686)
Proved Reserves at Dec. 31, 2019	**7,770**	**20,121**	**112,812**	**140,703**	**14,327**	**24,242**	**933,737**	**314,693**

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, 2018	3,024	7,215	60,631	70,869	7,277	10,129	300,449	129,909
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(232)	-	-	(232)	(9)	(163)	-	(268)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	158	-	17,428	17,586	2,034	131	74,186	32,007
Economic factors	3	7	(201)	(190)	(105)	(1,940)	684	(504)
Technical revisions	(165)	(752)	(9,617)	(10,535)	(803)	(761)	(141,706)	(35,082)
Production	-	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2019	**2,788**	**6,470**	**68,240**	**77,498**	**8,396**	**7,395**	**233,613**	**126,061**

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, 2018	12,660	28,395	167,160	208,216	21,060	41,137	1,149,511	427,718
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(1,214)	-	-	(1,214)	(27)	(483)	-	(1,321)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	546	-	39,159	39,706	4,374	872	163,079	71,405
Economic factors	(15)	(108)	(1,158)	(1,282)	(180)	(2,152)	(3,692)	(2,435)
Technical revisions	-	26	(9,152)	(9,127)	(757)	289	(48,542)	(17,926)
Production	(1,420)	(1,722)	(14,957)	(18,098)	(1,749)	(8,026)	(93,008)	(36,686)
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**

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 independent reserves evaluators' 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)		
2020	$526	$550
2021	$485	$511
2022	$258	$513
2023	$31	$408
2024	$35	$72
2025	$6	$7
Remainder	$7	$5
Total FDC Undiscounted	$1,347	$2,066
Total FDC Discounted at 10%	$1,183	$1,723

F&D AND FD&A COSTS – *including FDC*

($ millions except for per BOE amounts)	2019	2018	2017	3 Year
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$618.9	$593.8	$458.0	$1,670.7
Net change in Future Development Costs	$47.0	$309.1	$102.8	$458.9
Gross Reserves additions (MMBOE)	51.0	65.7	58.0	174.7
F&D costs ($/BOE)	**$13.05**	**$13.74**	**$9.68**	**$12.19**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$633.7	$612.7	$415.1	$1,661.5
Net change in Future Development Costs	$44.0	$308.1	$85.1	$437.1
Gross Reserves additions (MMBOE)	49.7	64.1	45.6	159.3
FD&A costs ($/BOE)	**$13.63**	**$14.37**	**$10.98**	**$13.17**
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$618.9	$593.8	$458.0	$1,670.7
Net change in Future Development Costs	$2.4	$309.3	$114.0	$425.7
Gross Reserves additions (MMBOE)	54.6	54.1	50.5	159.3
F&D costs ($/BOE)	**$11.37**	**$16.69**	**$11.32**	**$13.16**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$633.7	$612.7	$415.1	$1,661.5
Net change in Future Development Costs	$(0.5)	$308.3	$96.7	$404.5
Gross Reserves additions (MMBOE)	53.6	52.9	41.0	147.5
FD&A costs ($/BOE)	**$11.82**	**$17.42**	**$12.48**	**$14.01**
Proved Developed Producing Reserves				
Finding & Development Costs				
Capital Expenditures	$618.9	$593.8	$458.0	$1,670.7
Gross Reserves additions (MMBOE)	38.8	45.4	34.8	118.9
F&D costs ($/BOE)	**$15.97**	**$13.08**	**$13.17**	**$14.05**

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, 2020 (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	Natural Gas Alberta Spot @ AECO CDN$/MMBtu	Exchange Rate US$/CDN$	Inflation Rate %/year
2020	61.00	72.64	51.23	2.62	2.04	0.760	0.0
2021	63.75	76.06	56.11	2.87	2.32	0.770	1.7
2022	66.18	78.35	57.72	3.06	2.62	0.785	2.0
2023	67.91	80.71	59.45	3.17	2.71	0.785	2.0
2024	69.48	82.64	61.09	3.24	2.81	0.785	2.0
2025	71.07	84.60	62.75	3.32	2.89	0.785	2.0
2026	72.68	86.57	64.43	3.39	2.96	0.785	2.0
2027	74.24	88.49	66.04	3.45	3.03	0.785	2.0
2028	75.73	90.31	67.55	3.53	3.09	0.785	2.0
2029	77.24	92.17	69.08	3.60	3.16	0.785	2.0
2030	78.79	94.01	70.46	3.67	3.23	0.785	2.0
2031	80.36	95.89	71.87	3.74	3.29	0.785	2.0
2032	81.97	97.81	73.31	3.82	3.36	0.785	2.0
2033	83.61	99.76	74.78	3.89	3.43	0.785	2.0
2034	85.28	101.76	76.27	3.97	3.49	0.785	2.0
Thereafter	[4]	[4]	[4]	[4]	[4]	0.785	[4]

(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, 2019, ($ Millions, discounted at)	**0%**	**5%**	**10%**	**15%**
Proved developed producing	$3,635	$2,835	$2,317	$1,970
Proved developed non-producing	$27	$21	$17	$14
Proved undeveloped	$1,751	$1,174	$824	$595
Total Proved	$5,414	$4,029	$3,158	$2,579
Probable	$3,470	$1,902	$1,192	$815
Total Proved Plus Probable Reserves (before tax)	$8,884	$5,932	$4,349	$3,394

Contingent Resources

The following table provides a breakdown of the economic, unrisked best estimate contingent resources associated with a portion of Enerplus' Fort Berthold, Marcellus, and Canadian waterflood assets as at December 31, 2019. 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, 2020, 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 evaluations of contingent resources associated with a portion of Enerplus' Canadian waterflood 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, 2019. 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
Canada			
Waterfloods – IOR/EOR on a portion of waterfloods	31.1	MMBOE	44.2
Total Canada	**31.1**	**MMBOE**	**44.2**
United States Properties			
Fort Berthold – Bakken/Three Forks Tight Oil wells	45.1	MMBOE	94.7
Marcellus - Shale gas	663.5	Bcf	37.0
Total United States	**155.6**	**MMBOE**	**131.7**
Total Company	**186.7**	**MMBOE**	**175.9**

LIVE CONFERENCE CALL

Enerplus plans to hold a conference call hosted by Ian C. Dundas, President and CEO, today, February 21, 2020 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 21, 2020
Time: 9:00 am MT/11:00 am ET
Dial-In: 416-764-8688
1-888-390-0546 (toll free)
Conference ID: 95232985
Audiocast: https://event.on24.com/wcc/r/2176880/2A1E6E1D61161621B4188BA9FED0158B

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: 232985 #

Electronic copies of Enerplus' 2019 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, 2019, 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, 2019 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, 2020. 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, 2019. 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, Enerplus' Fort Berthold properties, and a portion of Enerplus' Canadian crude oil 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: expected 2020 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 2020 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; our anticipated share repurchases under current and future normal course issuer bids; capital spending levels in 2020, 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 in 2020.

The forward-looking information contained in this news release reflects several material factors, expectations and assumptions including, without limitation: 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; current commodity price, 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; the availability of technology and processes to achieve environmental targets. 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; 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' 2019 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' 2019 MD&A.

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation