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NEWS RELEASE

February 22, 2019

Enerplus Announces Fourth Quarter and Full Year 2018 Financial and Operating Results and 2018 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' 2018 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 2018 cash flow from operating activities of $221.6 million and fourth quarter 2018 net income of $249.3 million, or $1.03 per share.

ANNUAL HIGHLIGHTS:

- 22% liquids production growth year-over-year
- 44% increase in adjusted funds flow year-over-year
- Generated free cash flow of $160 million in 2018
- Returned $108 million to shareholders in 2018 through share repurchases and dividends
- Ended 2018 with a net debt to adjusted funds flow ratio of 0.4 times
- Replaced 194% of 2018 production through proved plus probable ("2P") reserves additions, revisions and economic factors at a finding and development ("F&D") cost of $13.74 per BOE. This included material reserves growth in North Dakota where the Company replaced 244% of 2018 production
- Total 2P reserves increased 8% year-over-year, with 2P oil reserves increasing 9%

"We delivered strong results in 2018 having achieved the high-end of our production guidance range, along with generating meaningful free cash flow and returning over $100 million to shareholders," stated Ian C. Dundas, President and Chief Executive Officer. "With our best in class balance sheet, competitive oil growth outlook and visibility to free cash flow based on prevailing commodity prices, we remain well positioned to create value for our shareholders in 2019."

FOURTH QUARTER & FULL YEAR 2018 SUMMARY

Production

Fourth quarter 2018 production was at the high-end of the Company's guidance range and modestly higher than the prior quarter. Total fourth quarter production averaged 97,860 BOE per day, including oil and natural gas liquids production of 54,451 barrels per day (92% oil).

Full year 2018 production was also at the high-end of the Company's guidance range, averaging 93,216 BOE per day, including 49,910 barrels per day of crude oil and natural gas liquids (91% oil). Year-over-year, the Company's 2018 production increased by 10%, with liquids production increasing by 22%. This growth was largely driven by North Dakota production, which increased by 42%.

Cash Flow From Operating Activities and Adjusted Funds Flow

Fourth quarter cash flow from operating activities increased to $221.6 million from $216.1 million in the third quarter. Full year 2018 cash flow from operating activities was $738.8 million, 55% higher than 2017.

Fourth quarter adjusted funds flow increased to $214.3 million from $210.4 million in the third quarter. Fourth quarter adjusted funds flow benefited from a $27.2 million Alternative Minimum Tax ("AMT") refund expected to be realized in 2019. Enerplus expects to realize the remaining $27.2 million in AMT refund in 2020 and 2021. Full year 2018 adjusted funds flow was $753.5 million, 44% higher than 2017.

Higher realized commodity prices and increased production volumes resulted in significant increases to cash flow from operating activities and adjusted funds flow for 2018 compared to 2017.

Net Income and Adjusted Net Income

Fourth quarter net income was $249.3 million ($1.03 per share) compared to $86.9 million ($0.35 per share) in the prior quarter. Full year 2018 net income was $378.3 million ($1.55 per share) compared to $237.0 million ($0.98 per share) in 2017.

Fourth quarter adjusted net income was $102.2 million ($0.42 per share) compared to $97.3 million ($0.40 per share) in the prior quarter. Full year 2018 adjusted net income was $344.8 million ($1.41 per share) compared to $132.2 million ($0.55 per share) in 2017. 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. The calculation of adjusted net income is provided in the "Non-GAAP Measures" section in the 2018 MD&A.

Pricing Realizations and Cost Structure

Enerplus' realized Bakken crude oil price differential widened to US$5.60 per barrel below WTI in the fourth quarter, from US$2.54 per barrel in the previous quarter. The weaker fourth quarter pricing was due to significant seasonal refinery maintenance which temporarily reduced demand for Bakken oil. Enerplus' Bakken crude oil price differential for the full year 2018 averaged US$3.78 per barrel below WTI, approximately flat year-over-year.

Enerplus' realized Marcellus natural gas sales price differential improved to US$0.34 per Mcf below NYMEX in the fourth quarter, compared to US$0.48 per Mcf in the previous quarter. Enerplus' Marcellus natural gas price differential for the full year 2018 averaged US$0.43 per Mcf below NYMEX, a 43% improvement year-over-year primarily driven by improved pipeline takeaway capacity in the Marcellus region.

Operating expenses in the fourth quarter and full year 2018 were $6.99 per BOE and $7.00 per BOE, respectively. Full year 2018 operating expenses were $0.63 per BOE higher year-over-year primarily due to the Company's higher liquids production weighting, which increased to 54% in 2018 from 48% in 2017.

Transportation costs in the fourth quarter and full year 2018 were $3.71 per BOE and $3.63 per BOE, respectively. Full year 2018 transportation costs were approximately flat compared to 2017.

Cash general and administrative ("G&A") expenses in the fourth quarter and full year 2018 were $1.40 per BOE and $1.47 per BOE, respectively. Full year 2018 cash G&A expenses per BOE were 10% lower compared to 2017.

Capital Expenditures and Balance Sheet Position

Capital spending was $72.1 million in the fourth quarter of 2018, bringing full year 2018 capital spending to $593.9 million, in-line with the Company's $585 million 2018 budget.

Enerplus remains in a strong financial position. The Company's total debt net of cash at December 31, 2018 was $333.5 million, comprised of $696.8 million of senior notes less $363.3 million in cash. At December 31, 2018, Enerplus was undrawn on its $800 million bank credit facility and had a net debt to adjusted funds flow ratio of 0.4 times.

Share Repurchases

During 2018 Enerplus repurchased 5,925,084 common shares at an average share price of $13.33 and a cost of $79.0 million. Subsequent to 2018 and up to February 20, 2019, the Company spent $6.7 million repurchasing 586,953 common shares at an average price of $11.40 per share.

The Company received approval from the board of directors to renew the Normal Course Issuer Bid upon expiry of the existing term on March 25th, 2019, subject to approval by the Toronto Stock Exchange ("TSX"). The proposed renewal will be for 7% of public float (within the meaning under the TSX rules) consistent with the current bid.

2018 RESERVES SUMMARY

- Replaced 194% of 2018 production, adding 65.7 MMBOE (51% oil) of 2P reserves from development activities (including revisions and economic factors).
- Material reserves growth was realized in North Dakota and the Marcellus. The Company replaced 244% of 2018 North Dakota production, adding 35.1 MMBOE of 2P reserves and 247% of 2018 Marcellus production, adding 187.4 Bcf of 2P reserves (including revisions and economic factors).
- F&D costs were $13.08 per BOE for proved developed producing ("PDP") reserves, $16.69 per BOE for proved reserves, and $13.74 per BOE for 2P reserves, including future development costs ("FDC").
- Three-year average F&D costs were $10.17 per BOE for PDP reserves, $10.27 per BOE for proved reserves, and $10.04 per BOE for 2P reserves, including FDC.
- Finding, development and acquisition ("FD&A") costs were $17.42 per BOE for proved reserves and $14.37 per BOE for 2P reserves, including FDC.
- Three-year average FD&A costs were $7.55 per BOE for proved reserves and $8.26 per BOE for 2P reserves, including FDC.
- Total 2P reserves were 427.7 MMBOE at year-end 2018, representing an 8% increase from year-end 2017.
- 2P reserves were comprised of 49% crude oil, 5% natural gas liquids, and 46% natural gas at year-end 2018.
- Proved developed producing reserves and total proved reserves represent 46% and 70% of 2P reserves, respectively.

ASSET ACTIVITY

Williston Basin

Williston Basin production averaged 47,420 BOE per day (83% oil) during the fourth quarter, 2% higher than the prior quarter. Fourth quarter Williston Basin production was comprised of 44,201 BOE per day in North Dakota and 3,219 BOE per day in Montana. Full year 2018 production from North Dakota averaged 39,659 BOE per day, a 42% increase year-over-year.

In the fourth quarter the Company drilled 12 gross operated wells (74% average working interest) and brought one gross operated well (100% working interest) on production.

As previously indicated, Enerplus expects North Dakota production to decline in the first quarter of 2019 due to modest fourth quarter completions activity and the Company's decision to slow completions early in 2019 as a result of significant oil price volatility. Following this, production is expected to meaningfully increase with strong growth forecast for the second half of 2019.

Marcellus

Marcellus production averaged 211 MMcf per day during the fourth quarter, approximately flat to the prior quarter. Full year 2018 production averaged 208 MMcf per day, a 5% increase year-over-year.

In the fourth quarter the Company participated in drilling 15 gross non-operated wells (11% average working interest) with 30 gross non-operated wells (5% average working interest) brought on production. At the time of this news release, 28 of these wells had more than 30 days on production. These wells had an average completed lateral length of 6,950 feet per well and average peak 30-day production rates per well of 18.1 MMcf per day.

Canadian Waterfloods

Canadian waterflood production averaged 9,731 BOE per day (93% oil) during the fourth quarter, modestly higher than the prior quarter. Full year 2018 production averaged 9,897 BOE per day, a reduction of approximately 3,050 BOE per day year-over-year primarily due to the sale of waterflood assets throughout 2017.

Average Daily Production[1]

	Three months ended December 31, 2018				Twelve months ended December 31, 2018			
	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	39.5	3.5	26.2	47.4	35.5	3.4	24.3	43.0
Marcellus	-	-	210.8	35.1	-	-	208.0	34.7
Canadian Waterfloods	9.0	0.1	3.5	9.7	9.1	0.1	4.1	9.9
Other[2]	1.4	0.9	19.9	5.6	0.8	1.0	23.5	5.7
Total	**50.0**	**4.5**	**260.4**	**97.8**	**45.4**	**4.5**	**259.8**	**93.2**

(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, 2018				Twelve months ended December 31, 2018			
	Operated		Non-Operated		Operated		Non-Operated	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Williston Basin	1	1.0	1	0.2	38	32.8	10	2.7
Marcellus	-	-	30	1.5	-	-	64	6.7
Canadian Waterfloods	4	2.9	6	0.0	6	4.8	7	0.0
Other[2]	-	-	4	0.3	4	3.7	7	1.2
Total	**5**	**3.9**	**41**	**2.1**	**48**	**41.3**	**88**	**10.6**

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

2019 GUIDANCE

Enerplus' previously announced and unchanged 2019 guidance is provided below.

Capital spending	$565 to $635 million
Average annual production	94,000 to 100,000 BOE/d
Average annual crude oil and natural gas liquids production	52,500 to 56,000 bbl/d
Average royalty and production tax rate	25%
Operating expense	$8.00/BOE
Transportation expense	$4.00/BOE
Cash G&A expense	$1.50/BOE

2019 Differential/Basis Outlook[1]

U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(4.00)/bbl
Marcellus basis (compared to NYMEX natural gas)	US$(0.30)/Mcf

(1) Excluding transportation costs.

SELECTED FINANCIAL RESULTS	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Financial (000's)				
Net Income	$ 249,315	$ 15,272	$ 378,279	$ 236,998
Cash Flow from Operating Activities	221,619	135,332	738,784	476,125
Adjusted Funds Flow(4)	214,285	199,559	753,506	524,064
Dividends to Shareholders - Declared	7,234	7,264	29,256	29,033
Total Debt Net of Cash(4)	333,523	325,831	333,523	325,831
Capital Spending	72,058	116,827	593,876	458,015
Property and Land Acquisitions	9,474	3,805	25,840	13,276
Property Divestments	886	(1,385)	6,912	56,196
Net Debt to Adjusted Funds Flow Ratio(4)	0.4x	0.6x	0.4x	0.6x
Financial per Weighted Average Shares Outstanding				
Net Income - Basic	$ 1.03	$ 0.06	$ 1.55	$ 0.98
Net Income - Diluted	1.02	0.06	1.53	0.96
Weighted Average Number of Shares Outstanding (000's) - Basic	242,344	242,129	244,076	241,929
Weighted Average Number of Shares Outstanding (000's) - Diluted	245,242	248,122	247,261	247,874
Selected Financial Results per BOE(1)(2)				
Oil & Natural Gas Sales(3)	$ 45.43	$ 41.72	$ 47.35	$ 36.93
Royalties and Production Taxes	(11.58)	(10.65)	(11.92)	(8.91)
Commodity Derivative Instruments	(0.31)	(0.39)	(1.05)	0.28
Cash Operating Expenses	(6.99)	(6.42)	(7.00)	(6.39)
Transportation Costs	(3.71)	(3.20)	(3.63)	(3.60)
General and Administrative Expenses	(1.40)	(1.55)	(1.47)	(1.63)
Cash Share-Based Compensation	0.23	(0.01)	(0.01)	(0.03)
Interest, Foreign Exchange and Other Expenses	(0.90)	(1.17)	(0.92)	(1.24)
Current Income Tax Recovery	3.03	6.15	0.80	1.55
Adjusted Funds Flow(4)	$ 23.80	$ 24.48	$ 22.15	$ 16.96

SELECTED OPERATING RESULTS	Three months ended December 31, 2018	Three months ended December 31, 2017	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Average Daily Production(2)				
Crude Oil (bbls/day)	49,968	42,374	45,424	36,935
Natural Gas Liquids (bbls/day)	4,483	4,448	4,486	3,858
Natural Gas (Mcf/day)	260,453	250,607	259,837	263,506
Total (BOE/day)	97,860	88,590	93,216	84,711
% Crude Oil and Natural Gas Liquids	56%	53%	54%	48%
Average Selling Price(2)(3)				
Crude Oil (per bbl)	$ 64.18	$ 65.91	$ 74.59	$ 58.69
Natural Gas Liquids (per bbl)	26.72	32.26	28.31	30.01
Natural Gas (per Mcf)	4.28	3.03	3.42	3.21

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes. See "Basis of Presentation" section in the Company's management discussion and analysis for the year ended December 31, 2018 ("2018 MD&A").
(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 in the 2018 MD&A.

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 95% of the net present value (discounted at 10%, before tax, using January 1, 2019 forecast prices and costs) 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 70% 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, 2019) 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 30% 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, 2019 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, 2018 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	9,062	17,969	58,284	85,315	8,443	28,707	591,890	197,191
Proved developed non-producing	15	135	921	1,071	138	2,213	3,748	2,202
Proved undeveloped	560	3,077	47,325	50,962	5,202	88	253,426	98,416
Total proved	9,637	21,181	106,530	137,347	13,783	31,007	849,063	297,809
Total probable	3,024	7,215	60,631	70,869	7,277	10,129	300,449	129,909
Proved plus Probable	**12,660**	**28,395**	**167,160**	**208,216**	**21,060**	**41,137**	**1,149,511**	**427,718**
Net								
Proved producing	7,514	15,506	46,815	69,835	6,875	29,245	475,633	160,856
Proved developed non-producing	14	124	751	889	103	2,081	3,039	1,845
Proved undeveloped	489	2,560	37,881	40,930	4,166	73	200,992	78,606
Total proved	8,017	18,189	85,447	111,654	11,143	31,399	679,664	241,307
Total probable	2,387	5,985	48,509	56,881	5,865	10,168	238,514	104,194
Proved plus Probable	**10,404**	**24,174**	**133,956**	**168,535**	**17,008**	**41,567**	**918,178**	**345,501**

Reserves Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2017 to December 31, 2018.

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, 2017	8,890	22,552	91,101	122,543	13,000	55,992	803,018	278,712
Acquisitions	-	-	175	175	23	-	114	217
Dispositions	(2)	-	(239)	(242)	(96)	(6,447)	(126)	(1,433)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	1,501	500	21,485	23,485	2,292	976	77,554	38,866
Economic factors	64	127	(84)	107	(99)	(1,597)	(1,240)	(465)
Technical revisions	1,007	(437)	7,236	7,806	232	(8,602)	54,558	15,697
Production	(1,823)	(1,560)	(13,144)	(16,527)	(1,570)	(9,314)	(84,814)	(33,785)
Proved Reserves at Dec. 31, 2018	**9,637**	**21,181**	**106,530**	**137,347**	**13,783**	**31,007**	**849,063**	**297,809**

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, 2017	2,719	7,635	58,125	68,479	7,752	21,289	233,742	118,737
Acquisitions	-	-	39	39	5	-	26	48
Dispositions	(1)	-	(65)	(66)	(42)	(2,293)	(37)	(496)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	1,150	1,023	13,675	15,848	1,397	395	70,598	29,077
Economic factors	(109)	25	(71)	(155)	(95)	(1,523)	549	(413)
Technical revisions	(735)	(1,468)	(11,073)	(13,276)	(1,739)	(7,739)	(4,430)	(17,043)
Production	-	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2018	**3,024**	**7,215**	**60,631**	**70,869**	**7,277**	**10,129**	**300,449**	**129,909**

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, 2017	11,609	30,187	149,227	191,023	20,752	77,281	1,036,760	397,448
Acquisitions	-	-	214	214	28	-	139	265
Dispositions	(3)	-	(305)	(307)	(137)	(8,741)	(162)	(1,929)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	2,651	1,522	35,160	39,333	3,689	1,372	148,152	67,943
Economic factors	(45)	152	(155)	(48)	(194)	(3,120)	(691)	(878)
Technical revisions	272	(1,906)	(3,836)	(5,470)	(1,507)	(16,341)	50,129	(1,346)
Production	(1,823)	(1,560)	(13,144)	(16,527)	(1,570)	(9,314)	(84,814)	(33,785)
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**

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 future development costs 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)		
2019	656	714
2020	527	543
2021	106	524
2022	34	163
2023	13	65
2024	6	7
Remainder	5	6
Total FDC Undiscounted	**1,348**	**2,022**
Total FDC Discounted at 10%	**1,213**	**1,739**

F&D AND FD&A COSTS – *including future development costs*

($ millions except for per BOE amounts)	2018	2017	2016	3 Year
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$593.8	$458.0	$209.1	$1,260.9
Net change in Future Development Costs	$309.1	$102.8	$(4.0)	$407.9
Gross Reserves additions (MMBOE)	65.7	58.0	42.6	166.3
F&D costs ($/BOE)	**$13.74**	**$9.68**	**$4.82**	**$10.04**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$612.7	$415.1	$(335.1)	$692.7
Net change in Future Development Costs	$308.1	$85.1	$(94.5)	$298.6
Gross Reserves additions (MMBOE)	64.1	45.6	10.3	119.9
FD&A costs ($/BOE)	**$14.37**	**$10.98**	**$(41.60)**	**$8.26**
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$593.8	$458.0	$209.1	$1,260.9
Net change in Future Development Costs	$309.3	$114.0	$(124.4)	$298.9
Gross Reserves additions (MMBOE)	54.1	50.5	47.2	151.9
F&D costs ($/BOE)	**$16.69**	**$11.32**	**$1.79**	**$10.27**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$612.7	$415.1	$(335.1)	$692.7
Net change in Future Development Costs	$308.3	$96.7	$(202.1)	$202.9
Gross Reserves additions (MMBOE)	52.9	41.0	24.7	118.6
FD&A costs ($/BOE)	**$17.42**	**$12.48**	**$(21.74)**	**$7.55**
Proved Developed Producing Reserves				
Finding & Development Costs				
Capital Expenditures	$593.8	$458.0	$209.1	$1,260.9
Gross Reserves additions (MMBOE)	45.4	34.8	43.9	124.0
F&D costs ($/BOE)	**$13.08**	**$13.17**	**$4.77**	**$10.17**

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, 2019 (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
2019	58.58	67.30	43.92	3.00	1.88	0.757	0.0
2020	64.60	75.84	52.76	3.13	2.31	0.782	2.0
2021	68.20	80.17	59.10	3.33	2.74	0.797	2.0
2022	71.00	83.22	61.60	3.51	3.05	0.803	2.0
2023	72.81	85.34	63.39	3.62	3.21	0.807	2.0
2024	74.59	87.33	65.14	3.70	3.31	0.808	2.0
2025	76.42	89.50	66.99	3.77	3.39	0.808	2.0
2026	78.40	91.89	69.06	3.85	3.46	0.808	2.0
2027	79.98	93.76	70.60	3.92	3.54	0.808	2.0
2028	81.59	95.68	72.17	4.01	3.62	0.808	2.0
2029	83.22	97.60	73.62	4.09	3.69	0.808	2.0
2030	84.89	99.55	75.09	4.17	3.77	0.808	2.0
2031	86.58	101.54	76.59	4.25	3.84	0.808	2.0
2032	88.31	103.57	78.12	4.34	3.92	0.808	2.0
2033	90.08	105.64	79.68	4.42	4.00	0.808	2.0
Thereafter	(4)	(4)	(4)	(4)	(4)	0.808	(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, 2018, ($ Millions, discounted at)	0%	5%	10%	15%
Proved developed producing	4,507	3,257	2,568	2,140
Proved developed non-producing	17	12	8	6
Proved undeveloped	1,714	1,057	695	467
Total Proved	**6,238**	**4,326**	**3,271**	**2,613**
Probable	3,875	2,080	1,311	911
Total Proved Plus Probable Reserves (before tax)	**10,113**	**6,405**	**4,582**	**3,523**

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, 2018. 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, 2019, 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, 2018. 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	31.6	MMBOE	44.2
Total Canada	**31.6**	**MMBOE**	**44.2**
United States Properties			
Fort Berthold – Bakken/Three Forks Tight Oil wells	70.9	MMBOE	135.6
Marcellus - Shale gas	699.7	Bcf	53.3
Total United States	**187.5**	**MMBOE**	**189.0**
Total Company	**219.2**	**MMBOE**	**233.2**

LIVE CONFERENCE CALL

Enerplus plans to hold a conference call hosted by Ian C. Dundas, President and CEO, today, February 22, 2019 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 22, 2019
Time: 9:00 am MT/11:00 am ET
Dial-In: 416-764-8688
1-888-390-0546 (toll free)
Audiocast: https://event.on24.com/wcc/r/1909686/E4770801B2052FD2C6F7BC8B25C2B413

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: 121297

Electronic copies of Enerplus' 2018 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

Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under IFRS and Canadian industry protocol oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. In order to continue to be comparable with Enerplus' Canadian peer companies, the summary results contained within this news release presents Enerplus' production and BOE measures on a before royalty company interest basis with the exception of reserves BOE measures which are on a working interest basis.

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), being Enerplus' working interest before deduction of any royalties. Enerplus' oil and gas reserves statement for the year ended December 31, 2018, 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, 2018 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.

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, 2019. Enerplus expects to develop these contingent resources in the coming years however it is too early in their development for these resources to be classified as reserves at this time. 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, 2018. 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 2019 average production volumes, timing thereof and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting our 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 2019 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 2019, net debt to adjusted funds-flow ratio, financial capacity and liquidity and capital resources to fund capital spending and working capital requirements.

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; and the extent of our liabilities. In addition, our 2019 guidance contained in this news release is based on the following: a WTI price of US$50.00/bbl to US$55.00/bbl, a NYMEX price of US$3.00/Mcf, and a USD/CDN exchange rate of 1.32. 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' 2018 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' 2018 MD&A.

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation