NEWS RELEASE

ENERPLUS CORPORATION
The Dome Tower, Suite 3000
333 – 7th Avenue SW
Calgary, Alberta T2P 2Z1
T. 403-298-2200 F. 403-298-2211
www.enerplus.com

February 23, 2018

Enerplus Announces Fourth Quarter and Full Year 2017 Financial and Operating Results and 2017 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' 2017 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 2017 net income of $15.3 million, or $0.06 per share, and fourth quarter adjusted funds flow of $199.6 million. Full year 2017 net income was $237.0 million, or $0.98 per share, and full year 2017 adjusted funds flow was $524.1 million.

HIGHLIGHTS:

- Fourth quarter adjusted funds flow was $199.6 million, which includes $50.1 million related to a portion of the expected U.S. Alternative Minimum Tax ("AMT") refund. Excluding the AMT refund, adjusted funds flow was $149.5 million, a 65% increase quarter-over-quarter
- Full year 2017 adjusted funds flow, excluding the AMT refund, increased by 55% compared to 2016
- Fourth quarter netback before hedging improved by 44% to $21.45 per BOE compared to the previous quarter
- Delivered 28% crude oil production growth from the first quarter to the fourth quarter of 2017
- North Dakota production increased by 70% from the first quarter to the fourth quarter of 2017
- Balance sheet remains among the strongest in the North American peer group, ending 2017 with a net debt to adjusted funds flow ratio of 0.6 times
- Replaced 189% of 2017 production through proved plus probable ("2P") reserves additions, revisions and economic factors at a finding and development ("F&D") cost of $9.68 per BOE. This included material reserves growth in North Dakota where the Company replaced 414% of 2017 production

"In 2017 we accomplished what we set out to do, namely delivering profitable growth, maintaining our disciplined approach to capital allocation, and continuing our strong operating momentum," stated Ian C. Dundas, President and Chief Executive Officer. "We also continued to have success in focusing our business through divesting non-strategic assets which has further improved our cost structure and margin and reduced liabilities. As evidenced by our strong fourth quarter cash flow and netback, our company is well positioned to continue to generate robust cash flow per share growth and create long-term value for our shareholders."

FOURTH QUARTER & FULL YEAR 2017 SUMMARY

Production

Fourth quarter 2017 production was 88,590 BOE per day, above the Company's fourth quarter guidance range of 86,000 to 88,000 BOE per day, and an increase of 12% from the third quarter of 2017. The Company's crude oil and natural gas liquids production averaged 46,822 barrels per day (91% oil) in the fourth quarter, also above its fourth quarter guidance range of 45,000 to 46,000 barrels per day, and an increase of 20% from the third quarter of 2017. The production outperformance in the fourth quarter was primarily driven by higher than forecasted North Dakota and Marcellus volumes, which together accounted for 76% of fourth quarter production.

Full year 2017 production averaged 84,711 BOE per day, including 40,793 barrels per day of crude oil and natural gas liquids (91% oil). Full year production was just above the Company's guidance of 84,000 BOE per day of total production and 40,500 barrels per day of crude oil and natural gas liquids.

Adjusted Funds Flow, Netback and Net Income

The continued improvement of Enerplus' pricing realizations in the Bakken and Marcellus, combined with the reductions to the Company's cost structure, have significantly strengthened the cash flow generating capability of the business. Fourth quarter 2017 adjusted funds flow was $199.6 million, which included $50.1 million related to a portion of the AMT refund receivable as a result of the enactment of U.S. tax reform legislation on December 22, 2017. Excluding the impact of the AMT refund, Enerplus' fourth quarter normalized adjusted funds flow was $149.5 million, 65% higher than the previous quarter. Full year 2017 adjusted funds flow was $524.1 million, or $474.0 million excluding the impact of the AMT refund, representing a 55% increase compared to 2016.

Enerplus' netback, before commodity hedging, was $21.45 per BOE in the fourth quarter of 2017. This represents a 44% increase from the prior quarter and a 47% increase from the same period in 2016. The significant improvement in operating netback was driven by improved pricing differentials in the Bakken and Marcellus, the Company's lower cost structure, and higher benchmark oil prices.

Fourth quarter net income was $15.3 million and included a $46.2 million non-cash deferred income tax expense from the remeasurement of the Company's U.S. deferred income tax assets for the U.S. federal income tax rate reduction from 35% to 21%. This expense is net of the reversal of the valuation allowance previously recorded on the Company's AMT credit carryovers. Full year 2017 net income was $237.0 million.

Pricing Realizations and Cost Structure

Enerplus' realized Bakken crude oil price differential averaged US$1.61 per barrel below WTI in the fourth quarter, an improvement from US$3.24 per barrel in the previous quarter. Spot Bakken prices strengthened considerably throughout 2017 due to the improved egress capacity from the Bakken. Enerplus' average Bakken crude oil price differential for the full year 2017 was US$3.72 per barrel below WTI, in-line with the Company's guidance of US$4.00 per barrel. The Company expects the strength in Bakken pricing to continue and is projecting a 2018 realized differential of US$2.50 per barrel below WTI.

Enerplus' realized Marcellus natural gas sales price differential narrowed to US$0.81 per Mcf below NYMEX in the fourth quarter, compared to US$1.02 per Mcf in the previous quarter. Although Marcellus pricing was weak during October, it strengthened considerably in November and December in response to seasonal heating demand and additional industry pipeline capacity coming into service. Enerplus' average Marcellus natural gas price differential for the full year 2017 was US$0.76 per Mcf below NYMEX, in-line with the Company's guidance of US$0.80 per Mcf. Enerplus believes that the continued build-out of takeaway capacity is structurally improving pricing dynamics in the Marcellus region, and with an expected 2.1 Bcf per day of incremental takeaway projects in 2018 impacting northeast Pennsylvania, the Company anticipates the strength in regional pricing will continue. Enerplus has constructed its Marcellus marketing portfolio with a view to balancing risk mitigation through firm sales and transport commitments, with retaining exposure to in-basin pricing. As a result, Enerplus is positioned to realize the benefit of improving in-basin pricing with only modest transportation commitments. Enerplus expects its 2018 realized Marcellus differential will average US$0.40 per Mcf below NYMEX, which excludes the Company's Marcellus firm transportation cost of US$0.18 per Mcf in 2018.

Enerplus continued to drive reductions to its cost structure in 2017 through divesting higher-cost assets and maintaining its focus on cost control and execution. Fourth quarter 2017 operating, transportation, and cash general and administrative ("G&A") expenses per BOE were all lower compared to the prior quarter.

- Operating expenses in the fourth quarter were $6.39 per BOE, 5% lower compared to the prior quarter. Full year 2017 operating expenses were $6.37 per BOE, 12% lower compared to 2016.

- Transportation costs in the fourth quarter were $3.20 per BOE, 11% lower compared to the prior quarter. Full year 2017 transportation costs were $3.60 per BOE, 15% higher compared to 2016 primarily due to the increased weighting of U.S. production with higher associated transport costs.

- Cash G&A expenses in the fourth quarter were $1.55 per BOE, 4% lower compared to the prior quarter. Full year 2017 cash G&A expenses were $1.63 per BOE, 7% lower compared to 2016.

Capital Expenditures and Balance Sheet Position

Capital spending was $116.8 million in the fourth quarter of 2017, bringing full year 2017 capital spending to $458.0 million, in-line with the Company's $450 million 2017 budget.

Enerplus further strengthened its financial position during 2017, reducing net debt by 13% year-over-year. Total debt net of cash at December 31, 2017 was $325.8 million. Total debt was comprised of $672.3 million in senior notes outstanding. The Company was undrawn on its $800 million bank credit facility and had a cash balance of $346.5 million. At December 31, 2017, Enerplus' net debt to adjusted funds flow ratio was 0.6 times.

Divestment Activity and Asset Retirement Obligation

During the fourth quarter of 2017 and first quarter of 2018, Enerplus closed a portion of the previously announced divestments of non-core properties in Alberta. These divestments had associated production of approximately 1,000 BOE per day. Enerplus continues to explore options to divest additional Canadian natural gas assets.

Throughout 2017, Enerplus divested approximately 7,700 BOE per day (66% natural gas) of production in aggregate from predominantly lower-margin properties in Canada. These divestments have helped reduce Enerplus' asset retirement obligation ("ARO") by 35% year-over-year. The present value of the Company's ARO was $117.7 million at December 31, 2017, compared to $181.7 million at December 31, 2016.

AVERAGE DAILY PRODUCTION(1)

	Three months ended December 31, 2017			Twelve months ended December 31, 2017		
	Oil & NGL (Mbbl/d)	Natural gas (MMcf/d)	Total Production (Mboe/d)	Oil & NGL (Mbbl/d)	Natural gas (MMcf/d)	Total Production (Mboe/d)
Williston Basin	35.8	20.1	39.2	28.7	19.2	31.9
Marcellus	-	193.2	32.2	-	198.0	33.0
Canadian Waterfloods(2)	9.6	6.6	10.7	10.9	12.2	12.9
Other(2)	1.4	30.7	6.5	1.2	34.0	6.9
Total	**46.8**	**250.6**	**88.6**	**40.8**	**263.5**	**84.7**

(1) Table may not add due to rounding.
(2) Includes volumes from Canadian properties that were divested in 2017.

SUMMARY OF WELLS BROUGHT ON-STREAM(1)

	Three months ended December 31, 2017				Twelve months ended December 31, 2017			
	Operated		Non Operated		Operated		Non Operated	
	Gross	*Net*	*Gross*	*Net*	*Gross*	*Net*	*Gross*	*Net*
Williston Basin	7	5.2	6	2.1	36	28.5	8	2.5
Marcellus	-	-	28	3.4	-	-	70	7.2
Canadian Waterfloods	-	-	-	-	6	6.0	-	-
Other	-	-	-	-	1	1.0	-	-
Total	**7**	**5.2**	**34**	**5.4**	**43**	**35.5**	**78**	**9.7**

(1) Table may not add due to rounding.

2017 RESERVES SUMMARY

- Replaced 189% of 2017 production, adding 58.0 MMBOE (61% 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 414% of 2017 North Dakota production, adding 42.2 MMBOE of 2P reserves and 132% of 2017 Marcellus production, adding 95.4 Bcf of 2P reserves (including revisions and economic factors).
- F&D costs were $13.17 per BOE for proved developed producing reserves, $11.32 per BOE for proved reserves, and $9.68 per BOE for 2P reserves, including future development costs ("FDC").
- Three-year average F&D costs were $9.66 per BOE for proved developed producing reserves, $9.16 per BOE for proved reserves, and $7.86 per BOE for 2P reserves, including FDC.

- Finding, development and acquisition ("FD&A) costs were $12.48 per BOE for proved reserves and $10.98 per BOE for 2P reserves, including FDC. 2017 divestments were generally comprised of lower-margin Canadian properties. No reserves were acquired in 2017.
- Three-year average FD&A costs were $3.41 per BOE for proved reserves and $1.05 per BOE for 2P reserves, including FDC.
- Total 2P reserves, net of divestments, were 397.4 MMBOE at year-end 2017, representing a 4% increase from year-end 2016. Excluding divestments, 2P reserves increased by 7% in 2017.
- 2P reserves were comprised of 48% crude oil, 5% natural gas liquids, and 47% natural gas at year-end 2017.
- Total proved reserves account for 70% of 2P reserves. Proved developed producing reserves represent 67% of total proved reserves and 47% of 2P reserves.
- Enerplus' 2P reserves life index increased to 12.6 years at year-end 2017, from 12.3 years at year-end 2016.

ASSET ACTIVITY

Williston Basin

Williston Basin production averaged 39,195 BOE per day (83% oil) during the fourth quarter of 2017, 27% higher than the third quarter. Fourth quarter Williston Basin production was comprised of 35,474 BOE per day in North Dakota and 3,721 BOE per day in Montana. Enerplus re-established meaningful growth in North Dakota during 2017 delivering a 70% production increase over the course of the year (from the first quarter to the fourth quarter of 2017).

In the fourth quarter, Enerplus brought on-stream seven gross operated wells (74% average working interest) across its acreage at Fort Berthold with an average completed lateral length of 7,540 feet per well and average peak 30-day production rates per well of 1,443 BOE per day (76% oil, on a three-stream basis). This average rate includes production from two wells that were producing at restricted rates.

Enerplus continued to see strong outperformance from the four wells on its Snakes pad that were brought on-stream toward the end of the third quarter. On average, the Snakes wells have produced approximately 160,000 barrels of oil per well in 120 days on production, including the Smooth Green well which has produced over 240,000 barrels of oil in 120 days.

The Company drilled six gross operated wells (77% average working interest) in the fourth quarter.

Enerplus expects a decline in production from North Dakota in the first quarter of 2018, relative to the fourth quarter of 2017, followed by sequential quarterly production growth for the remainder of the year. The expected decline in the first quarter is due to a completions schedule that results in on-stream activity weighted to the back half of the first quarter – in part to mitigate the impact of severe weather during December and January.

Enerplus expects to spend approximately 75% of its 2018 capital budget in North Dakota running two-operated drilling rigs and one dedicated completions crew in 2018. North Dakota production in 2018 is projected to grow by over 30% year-over-year.

Marcellus

Marcellus production averaged 193 MMcf per day during the fourth quarter, a 2% increase from the previous quarter. Fourth quarter production was impacted by approximately 35 MMcf per day of price related production curtailments during October. Enerplus returned to producing at higher rates in November and December in response to strengthening regional natural gas prices. Full year 2017 production from the Marcellus averaged 198 MMcf per day.

Twenty-eight gross non-operated wells (12% average working interest) were brought on-stream during the quarter, of which 22 currently have over 30-days on production. These 22 wells have an average completed lateral length of 5,800 feet per well and average peak 30-day production rates per well of 13.1 MMcf per day.

The Company participated in drilling nine gross non-operated wells (20% average working interest) during the fourth quarter.

Enerplus expects to spend approximately 10% of its 2018 capital budget in the Marcellus which is projected to keep production levels broadly flat relative to 2017.

Canadian Waterfloods

Canadian waterflood production averaged 10,671 BOE per day (88% oil) during the fourth quarter, a decrease of 8% from the previous quarter primarily due to the planned shut-in of certain production wells at Ante Creek in preparation for conversion to water injection wells, and weather related downtime at Medicine Hat.

Enerplus expects to spend approximately 10% of its 2018 capital budget across its Canadian waterflood portfolio.

DJ Basin

Through leasing and farm-in activity, Enerplus has established a land position of approximately 35,000 net acres in the DJ Basin, located in northwest Weld County, Colorado, for a modest entry price. Enerplus has drilled and completed one well (Maple 8-67-36-25C) to date. The pilot-hole was drilled to a total vertical depth of 7,480 feet and a 388 foot section was cored spanning the entire Niobrara-Codell interval. Core data indicated significant oil saturations throughout the entire interval. Subsequent to coring, Enerplus drilled a 9,272 foot horizontal well in the Codell formation and completed the well using a high-proppant and high-fluid intensity slick water completion. The well has produced 46,920 barrels of oil in 156 days on production and had a peak consecutive 90 day production rate of 434 BOE per day (78% oil). Due to the high fluid intensity completion and flowback management, the oil cut and oil rate inclined for most of the well's initial production period. The well was shut in for several weeks during the first quarter of 2018 for surface facility modifications and was only recently brought back on production. Prior to this the well was producing at a relatively stable rate of approximately 400 BOE per day (78% oil) after over five months on production and is tracking cumulative production of 100,000 BOE in its first 12 months.

The well is producing light oil with a gravity of approximately 39 degrees API which has allowed for oil sales at the lease at a differential below WTI of US$2.25 per barrel. Enerplus will continue to monitor the results of the Maple well and plans to continue delineation activity to test the extent of commerciality across its acreage position. Enerplus is planning to drill up to three wells in the DJ Basin in 2018.

2018 GUIDANCE

Enerplus' previously announced and unchanged 2018 guidance is provided below.

Capital spending	$535 – 585 million
Average annual production	86,000 – 91,000 BOE/d
Average annual crude oil and natural gas liquids production	46,000 – 50,000 bbl/d
Average royalty and production tax rate	25%
Operating expense	$7.00/BOE
Transportation expense	$3.60/BOE
Cash G&A expense	$1.65/BOE

2018 Differential/Basis Outlook[(1)]	
U.S. Bakken crude oil differential (compared to WTI crude oil)	US$(2.50)/bbl
Marcellus basis (compared to NYMEX natural gas)	US$(0.40)/Mcf

(1) Excluding transportation costs

RISK MANAGEMENT UPDATE

Enerplus' commodity hedging positions, as at February 20, 2018, are provided in the tables below. Based on the mid-point of its 2018 production guidance (net of royalties), Enerplus has approximately 65% of 2018 crude oil production protected and 61% of 2019 crude oil production protected.

	WTI Crude Oil (US$/bbl) [(1)]						
	Jan 1, – Jan 31, 2018	**Feb 1, – Mar 31, 2018**	**Apr 1 – Jun 30, 2018**	**Jul 1 – Sep 30, 2018**	**Oct 1 – Dec 31, 2018**	**Jan 1, – Mar 31, 2019**	**Apr 1, – Dec 31, 2019**
Swaps							
Sold Swaps	$55.38	$58.32	$55.38	$53.73	$53.73	$53.73	-
Volume (bbls/d)	5,000	7,000	5,000	3,000	3,000	3,000	-
Three-Way Collars							
Sold Puts	$42.83	$42.83	$42.92	$42.71	$42.74	$44.05	$44.09
Volume (bbls/d)	13,000	13,000	15,000	18,000	20,000	16,000	20,000
Purchased Puts	$53.04	$53.04	$52.90	$52.53	$52.48	$53.69	$53.94
Volume (bbls/d)	13,000	13,000	15,000	18,000	20,000	16,000	20,000
Sold Calls	$61.99	$61.99	$61.73	$61.22	$61.10	$63.44	$63.84
Volume (bbls/d)	13,000	13,000	15,000	18,000	20,000	16,000	20,000

(1) Based on weighted average price (before premiums).

NYMEX Natural Gas (US$/Mcf) (1)

	Jan 1 – Mar 31, 2018	Apr 1, – Oct 31, 2018	Nov 1, – Dec 31, 2018
Collars			
Purchased Puts	$2.75	$2.75	$2.75
Volume (Mcf/d)	30,000	40,000	30,000
Sold Calls	$3.47	$3.38	$3.47
Volume (Mcf/d)	30,000	40,000	30,000

(1) Based on weighted average price (before premiums).

SELECTED FINANCIAL RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2017	2016	2017	2016
Financial (000's)				
Net Income/(Loss)	$ 15,272	$ 840,325	$ 236,998	$ 397,416
Adjusted Funds Flow[4]	199,559	107,730	524,064	305,605
Dividends to Shareholders	7,264	7,214	29,033	35,439
Debt Outstanding – net of Cash and Restricted Cash	325,831	375,520	325,831	375,520
Capital Spending	116,827	57,462	458,015	209,135
Property and Land Acquisitions	3,805	118,452	13,276	126,126
Property Divestments	(1,385)	389,750	56,196	670,364
Debt to Adjusted Funds Flow Ratio[4]	0.6x	1.2x	0.6x	1.2x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss) - Basic	$ 0.06	$ 3.49	$ 0.98	$ 1.75
Net Income/(Loss) - Diluted	0.06	3.43	0.96	1.72
Weighted Average Number of Shares Outstanding (000's)	242,129	240,483	241,929	226,530
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 41.72	$ 32.81	$ 36.93	$ 25.88
Royalties and Production Taxes	(10.65)	(7.60)	(8.91)	(5.77)
Commodity Derivative Instruments	(0.39)	1.12	0.28	2.36
Cash Operating Expenses	(6.42)	(7.22)	(6.39)	(7.31)
Transportation Costs	(3.20)	(3.44)	(3.60)	(3.14)
General and Administrative Expenses	(1.55)	(1.63)	(1.63)	(1.75)
Cash Share-Based Compensation	(0.01)	(0.17)	(0.03)	(0.09)
Interest, Foreign Exchange and Other Expenses	(1.17)	(0.97)	(1.24)	(1.28)
Current Tax Recovery	6.15	0.26	1.55	0.07
Adjusted Funds Flow[4]	$ 24.48	$ 13.16	$ 16.96	$ 8.97

SELECTED OPERATING RESULTS	Three months ended December 31,		Twelve months ended December 31,	
	2017	2016	2017	2016
Average Daily Production[2]				
Crude Oil (bbls/day)	42,374	37,128	36,935	38,353
Natural Gas Liquids (bbls/day)	4,448	4,413	3,858	4,903
Natural Gas (Mcf/day)	250,607	284,515	263,506	299,214
Total (BOE/day)	88,590	88,960	84,711	93,125
% Crude Oil and Natural Gas Liquids	53%	47%	48%	46%
Average Selling Price[2][3]				
Crude Oil (per bbl)	$ 65.91	$ 53.91	$ 58.69	$ 44.84
Natural Gas Liquids (per bbl)	32.26	21.31	30.01	15.29
Natural Gas (per Mcf)	3.03	2.89	3.21	2.06

(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, 2017 ("2017 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 2017 MD&A.

Average Benchmark Pricing	Three months ended December 31, 2017	2016	Twelve months ended December 31, 2017	2016
WTI crude oil (US$/bbl)	$ 55.40	$ 49.29	$ 50.95	$ 43.32
AECO natural gas – monthly index (CDN$/Mcf)	1.96	2.81	2.43	2.09
AECO natural gas – daily index (CDN$/Mcf)	1.69	3.09	2.16	2.16
NYMEX natural gas – last day (US$/Mcf)	2.93	2.98	3.11	2.46
US/CDN average exchange rate	1.27	1.33	1.30	1.32

Share Trading Summary For the twelve months ended December 31, 2017	CDN(1) – ERF (CDN$)	U.S.(2) – ERF (US$)
High	$ 13.35	$ 10.21
Low	$ 8.97	$ 6.52
Close	$ 12.31	$ 9.79

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

2017 Dividends per Share	CDN$	US$(1)
First Quarter Total	$ 0.03	$ 0.02
Second Quarter Total	$ 0.03	$ 0.02
Third Quarter Total	$ 0.03	$ 0.02
Fourth Quarter Total	$ 0.03	$ 0.02
Total Year to Date	$ 0.12	$ 0.08

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

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 92% of the net present value (discounted at 10%, before tax, using January 1, 2018 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 59% of the net present value (discounted at 10%, before tax, using McDaniel’s January 1, 2018 forecast prices and costs) of the Company's 2P reserves located in Canada and all of the Company's reserves associated with the Company's properties located in North Dakota, Montana and Colorado. The Company has evaluated the remaining 41% 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 used McDaniel's January 1, 2018 forecast prices and inflation rates 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, 2017 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	8,515	19,976	48,731	77,222	8,236	54,332	552,114	186,532
Proved developed non-producing	21	-	650	671	43	-	4,611	1,482
Proved undeveloped	354	2,576	41,721	44,651	4,720	1,660	246,294	90,697
Total proved	8,890	22,552	91,101	122,543	13,000	55,992	803,018	278,712
Total probable	2,719	7,635	58,125	68,479	7,752	21,289	233,742	118,737
Proved plus Probable	**11,609**	**30,187**	**149,227**	**191,023**	**20,752**	**77,281**	**1,036,760**	**397,448**
Net								
Proved producing	7,233	16,704	39,274	63,211	6,706	52,431	444,439	152,729
Proved developed non-producing	21	-	533	554	35	-	3,657	1,198
Proved undeveloped	332	2,170	33,436	35,938	3,784	1,295	195,795	72,569
Total proved	7,586	18,873	73,242	99,701	10,525	53,726	643,891	226,496
Total probable	2,381	6,249	46,591	55,221	6,247	20,225	185,576	95,768
Proved plus Probable	**9,966**	**25,122**	**119,833**	**154,921**	**16,772**	**73,951**	**829,467**	**322,264**

Reserves Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a gross basis, from December 31, 2016 to December 31, 2017.

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, 2016	11,621	30,232	77,566	119,419	11,825	95,769	726,614	268,307
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(691)	(4,730)	(134)	(5,555)	(122)	(22,970)	(127)	(9,527)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	354	390	19,609	20,353	2,231	28	78,672	35,701
Economic factors	(138)	(113)	(517)	(768)	(177)	(5,316)	(3,296)	(2,380)
Technical revisions	(541)	(1,012)	4,084	2,531	581	4,098	80,551	17,220
Production	(1,715)	(2,215)	(9,507)	(13,437)	(1,338)	(15,617)	(79,396)	(30,610)
Proved Reserves at Dec. 31, 2017	**8,890**	**22,552**	**91,101**	**122,543**	**13,000**	**55,992**	**803,018**	**278,712**

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, 2016	2,645	8,721	45,432	56,798	6,273	30,521	276,169	114,186
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(144)	(1,101)	(36)	(1,281)	(44)	(9,185)	(34)	(2,861)
Discoveries	-	-	-	-	-	-	-	-

Extensions & improved recovery	163	165	15,013	15,341	1,663	12	31,211	22,208
Economic factors	(7)	(39)	(10)	(56)	(73)	(2,393)	21	(525)
Technical revisions	62	(110)	(2,274)	(2,322)	(67)	2,335	(73,624)	(14,271)
Production	-	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2017	**2,719**	**7,635**	**58,125**	**68,479**	**7,752**	**21,289**	**233,742**	**118,737**

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, 2016	14,265	38,953	122,998	176,216	18,098	126,290	1,002,783	382,493
Acquisitions	-	-	-	-	-	-	-	-
Dispositions	(834)	(5,831)	(170)	(6,835)	(166)	(32,155)	(161)	(12,388)
Discoveries	-	-	-	-	-	-	-	-
Extensions & improved recovery	517	555	34,622	35,694	3,895	40	109,882	57,909
Economic factors	(145)	(152)	(527)	(824)	(250)	(7,709)	(3,275)	(2,905)
Technical revisions	(479)	(1,122)	1,810	209	513	6,432	6,927	2,949
Production	(1,715)	(2,215)	(9,507)	(13,437)	(1,338)	(15,617)	(79,396)	(30,610)
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**

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)		
2018	474	511
2019	437	605
2020	65	469
2021	32	83
2022	21	33
Remainder	11	13
Total FDC Undiscounted	1,040	1,714
Total FDC Discounted at 10%	925	1,469

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

($ millions except for per BOE amounts)	**2017**	**2016**	**2015**	**3 Year**
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$458.0	$209.1	$493.4	$1,160.6
Net change in Future Development Costs	$102.8	$(4.0)	$(142.2)	$(43.4)
Gross Reserves additions (MMBOE)	58.0	42.6	41.6	142.2
F&D costs ($/BOE)	**$9.68**	**$4.82**	**$8.44**	**$7.86**

Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$415.1	$(335.1)	$216.2	$296.2
Net change in Future Development Costs	$85.1	$(94.5)	$(212.5)	$(222.0)
Gross Reserves additions (MMBOE)	45.6	10.3	14.9	70.8
FD&A costs ($/BOE)	**$10.98**	**$(41.60)**	**$0.25**	**$1.05**
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$458.0	$209.1	$493.4	$1,160.6
Net change in Future Development Costs	$114.0	$(124.4)	$210.0	$199.6
Gross Reserves additions (MMBOE)	50.5	47.2	50.7	148.5
F&D costs ($/BOE)	**$11.32**	**$1.79**	**$13.88**	**$9.16**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$415.1	$(335.1)	$216.2	$296.2
Net change in Future Development Costs	$96.7	$(202.1)	$139.7	$34.3
Gross Reserves additions (MMBOE)	41.0	24.7	31.1	96.8
FD&A costs ($/BOE)	**$12.48**	**$(21.74)**	**$11.44**	**$3.41**
Proved Developed Producing Reserves				
Finding & Development Costs				
Capital Expenditures	$458.0	$209.1	$493.4	$1,160.6
Gross Reserves additions (MMBOE)	34.8	43.9	41.5	120.1
F&D costs ($/BOE)	**$13.17**	**$4.77**	**$11.90**	**$9.66**

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 price forecasts supplied by McDaniel as of January 1, 2018, (and utilized by 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.

McDaniel January 2018 Forecast Price 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
2018	58.50	70.10	45.20	3.00	2.25	0.790	0.0
2019	58.70	71.30	49.60	3.05	2.65	0.790	2.0
2020	62.40	74.90	53.60	3.25	3.05	0.800	2.0
2021	69.00	80.50	57.60	3.55	3.40	0.825	2.0
2022	73.10	82.80	59.20	3.80	3.60	0.850	2.0
2023	74.50	84.40	60.30	3.85	3.65	0.850	2.0
2024	76.00	86.10	61.60	3.95	3.75	0.850	2.0
2025	77.50	87.80	62.80	4.00	3.80	0.850	2.0
2026	79.10	89.60	64.10	4.10	3.90	0.850	2.0
2027	80.70	91.40	65.40	4.15	3.95	0.850	2.0
2028	82.30	93.20	66.60	4.25	4.05	0.850	2.0
2029	83.90	95.00	67.90	4.35	4.15	0.850	2.0
2030	85.60	97.00	69.40	4.45	4.25	0.850	2.0
2031	87.30	98.90	70.70	4.50	4.30	0.850	2.0
2032	89.10	100.90	72.10	4.60	4.35	0.850	2.0
Thereafter	(4)	(4)	(4)	(4)	(4)	0.850	(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, 2017, ($ Millions, discounted at)	0%	5%	10%	15%
Proved developed producing	3,940	2,789	2,171	1,796
Proved developed non-producing	16	11	8	6
Proved undeveloped	1,527	931	608	411
Total Proved	5,483	3,731	2,788	2,213
Probable	3,397	1,699	1,023	684
Total Proved Plus Probable Reserves (before tax)	8,880	5,430	3,811	2,897

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, 2017. These contingent resources are economic using McDaniel's January 1, 2018 forecast commodity prices, use established technologies and are all classified in the "development pending" maturity sub-class. 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' 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, 2017. 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	34.1	MMBOE	51.8
Total Canada	**34.1**	**MMBOE**	**51.8**
United States Properties			
Fort Berthold – Bakken/Three Forks Tight Oil wells	79.2	MMBOE	157.9
Marcellus - Shale gas	737.6	Bcf	71.2
Total United States	**202.1**	**MMBOE**	**229.1**
Total Company	**236.1**	**MMBOE**	**280.9**

LIVE CONFERENCE CALL

Enerplus plans to hold a conference call hosted by Ian C. Dundas, President and CEO, today, February 23, 2018 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 23, 2018
Time: 9:00 am MT/11:00 am ET
Dial-In: 647-427-7450
1-888-231-8191 (toll free)
Audiocast: http://event.on24.com/r.htm?e=1581105&s=1&k=682A07EC39874D5C3643C2C61153B241

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: 416-849-0833
1-855-859-2056 (toll free)
Passcode: 51750852

Electronic copies of Enerplus' 2017 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.

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. 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, 2017, 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, 2017 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 McDaniel's January 1, 2018 forecast prices. 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, 2017. 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.

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.

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", "plans", "budget", 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 2018 average production volumes 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 2018 and in the future; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A,

share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2018, net debt to adjusted funds-flow ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; and expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes.

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; 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; our ability to negotiate debt covenant relief under our bank credit facility and outstanding senior notes if required; the availability of third party services; and the extent of our liabilities. In addition, our 2018 guidance contained in this news release is based on the following: a WTI price of US$50.00/bbl, a NYMEX price of US$3.00/Mcf, and a USD/CDN exchange rate of 1.28. 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 decline of 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, including drilling and completions operations that offset our operations and that cause Enerplus to reduce or shut-in individual well production for safety reasons for a period of time; 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' 2017 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", "net debt to adjusted funds flow", and "netback" as 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. "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 net earnings and other measures prescribed by U.S. GAAP, the terms "adjusted funds flow", "net debt to adjusted funds flow", and "netback" 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' 2017 MD&A.

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation