enerPLUS

2017 FINANCIAL SUMMARY

Contents

Financial Summary	1
Highlights	3
Management’s Discussion and Analysis	5
Financial Statements	38
Five Year Detailed Statistical Review	66
Supplemental Information	68
Abbreviations & Definitions	69
Board of Directors	72
Officers	73
Corporate Information	74

2017 FINANCIAL SUMMARY

SELECTED FINANCIAL RESULTS	Three months ended December 31, 2017	Three months ended December 31, 2016	Twelve months ended December 31, 2017	Twelve months ended December 31, 2016
Financial (000's)				
Net Income	$ 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 - Basic	$ 0.06	$ 3.49	$ 0.98	$ 1.75
Net Income - 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, 2017	Three months ended December 31, 2016	Twelve months ended December 31, 2017	Twelve months ended December 31, 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
Net Wells Drilled	7	5	46	25

(1) Non-cash amounts have been excluded.
(2) Based on Company interest production volumes. See "Basis of Presentation" section in the following 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 following 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

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.

2017 HIGHLIGHTS

Financial and Operational Highlights

- Fourth quarter 2017 production was 88,590 BOE/day, above the Company's fourth quarter guidance of 86,000 to 88,000 BOE/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 bbls/day in the fourth quarter, also above its fourth quarter guidance of 45,000 to 46,000 bbls/day, and an increase of 20% from the third quarter of 2017.

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

- The Company reported fourth quarter 2017 net income of $15.3 million, or $0.06 per diluted share. Net income was impacted by a $46.2 million non-cash deferred 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 was partially offset by the reversal of the valuation allowance previously recorded on the Alternative Minimum Tax ("AMT") credit carryovers. Full year net income was $237.0 million compared to $397.4 million for the comparable 2016 period.

- Fourth quarter 2017 adjusted funds flow was $199.6 million, which included $50.1 million related to a portion of the AMT refund expected as a result of the U.S. tax reform legislation enacted in December 2017. Excluding the impact of the AMT refund, Enerplus' fourth quarter 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.

- The Company's realized pricing in the Bakken and the Marcellus improved in 2017. Enerplus' average Bakken crude oil price differential for the full year 2017 was US$3.72/bbl below WTI, a 50% improvement compared to 2016. Enerplus' average Marcellus natural gas price differential for the full year 2017 was US$0.76/Mcf below NYMEX, an 18% improvement compared to 2016.

- 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/BOE, 5% lower compared to the prior quarter. Full year 2017 operating expenses were $6.37/BOE, 12% lower compared to 2016.

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

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

- 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.

Reserves Highlights

- Replaced 189% of 2017 production, adding 58.0 MMBOE (61% oil) of proved plus probable ("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).

- Finding and development (“F&D”) costs were $13.17/BOE for proved developed producing reserves, $11.32/BOE for proved reserves, and $9.68/BOE for 2P reserves, including future development costs (“FDC”).

- Three-year average F&D costs were $9.66/BOE for proved developed producing reserves, $9.16/BOE for proved reserves, and $7.86/BOE for 2P reserves, including FDC.

- Finding, development and acquisition (“FD&A) costs were $12.48/BOE for proved reserves and $10.98/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/BOE for proved reserves and $1.05/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.

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

The following discussion and analysis of financial results is dated February 22, 2018 and is to be read in conjunction with the audited Consolidated Financial Statements (the "Financial Statements") of Enerplus Corporation ("Enerplus" or the "Company"), as at December 31, 2017 and 2016 and for the years ended December 31, 2017, 2016 and 2015.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for further information. The following MD&A also contains financial measures that do not have a standardized meaning as prescribed by accounting principles generally accepted in the United States of America ("U.S. GAAP"). See "Non-GAAP Measures" at the end of this MD&A for further information.

BASIS OF PRESENTATION

The Financial Statements and notes have been prepared in accordance with U.S. GAAP. All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Financial Statements. Certain prior period amounts have been restated to conform with current period presentation.

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a company interest basis, being the Company's working interest share before deduction of any royalties paid to others, plus the Company's royalty interests, unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101– Standards of Disclosure for Oil and Gas Activities ("NI 51-101") and may not be comparable to information produced by other entities. All reserves information presented herein has been prepared in accordance with NI 51-101 and is presented at December 31, 2017 unless otherwise stated.

In accordance with U.S. GAAP, oil and natural gas sales are presented net of royalties in the Financial Statements. Under International Financial Reporting Standards, industry standard is to present oil and natural gas sales before deduction of royalties and as such this MD&A presents production, oil and natural gas sales, and BOE measures before deduction of royalties to remain comparable with our peers.

The following table provides a reconciliation of our production volumes:

	Year ended December 31,		
Average Daily Production Volumes	**2017**	**2016**	**2015**
Company interest production volumes			
Crude oil (bbls/day)	36,935	38,353	41,639
Natural gas liquids (bbls/day)	3,858	4,903	4,763
Natural gas (Mcf/day)	263,506	299,214	360,733
Company interest production volumes (BOE/day)	84,711	93,125	106,524
Royalty volumes			
Crude oil (bbls/day)	7,531	7,198	7,471
Natural gas liquids (bbls/day)	777	932	971
Natural gas (Mcf/day)	47,722	50,270	59,077
Royalty volumes (BOE/day)	16,262	16,508	18,288
Net production volumes			
Crude oil (bbls/day)	29,404	31,155	34,168
Natural gas liquids (bbls/day)	3,081	3,971	3,792
Natural gas (Mcf/day)	215,784	248,944	301,656
Net production volumes (BOE/day)	68,449	76,617	88,236

2017 FOURTH QUARTER OVERVIEW

Fourth quarter production averaged 88,590 BOE/day, exceeding our fourth quarter guidance of 86,000 – 88,000 BOE/day, and increasing 12% compared to third quarter production of 79,128 BOE/day. Our liquids production increased by 20% to 46,822 bbls/day from 38,926 bbls/day in the third quarter, which exceeded our fourth quarter liquids guidance of 45,000 – 46,000 bbls/day. In the U.S., crude oil and liquids production increased during the fourth quarter with additional on-stream activity in North Dakota. Marcellus natural gas production was curtailed by 35,000 Mcf/day in October followed by strong unrestricted production in November and December as realized prices improved.

We reported net income of $15.3 million and adjusted funds flow of $199.6 million in the fourth quarter compared to net income of $16.1 million and adjusted funds flow of $90.4 million in the third quarter. Both net income and adjusted funds flow benefited from a $50.1 million Alternative Minimum Tax ("AMT") credit carryover refund, which we expect to realize in 2018. Additionally, crude oil and natural gas sales, net of royalties, increased $75 million or 38% compared to the third quarter, with improved pricing and the impact of higher production volumes. With higher production volumes, we saw a slight increase in operating costs and production taxes. Net income was also impacted by unrealized foreign exchange losses on the translation of our U.S. denominated debt and working capital, a non-cash deferred tax expense of $70.6 million primarily related to the remeasurement of our deferred income tax asset resulting from the U.S. federal income tax rate reduction, and the reversal of a portion of the valuation allowances previously recorded on our deferred income tax asset.

During the fourth quarter of 2017 and the first quarter of 2018 we closed a portion of the previously announced sale of non-core Canadian properties with associated production of approximately 1,000 BOE/day for minimal proceeds.

Selected Fourth Quarter Canadian and U.S. Financial Results

	Three months ended December 31, 2017			Three months ended December 31, 2016		
(millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	9,478	32,896	42,374	12,417	24,711	37,128
Natural gas liquids (bbls/day)	1,198	3,250	4,448	1,160	3,253	4,413
Natural gas (Mcf/day)	37,265	213,342	250,607	68,437	216,078	284,515
Total average daily production (BOE/day)	16,887	71,703	88,590	24,983	63,977	88,960
Pricing[2]						
Crude oil (per bbl)	$ 57.05	$ 68.46	$ 65.91	$ 48.44	$ 56.66	$ 53.91
Natural gas liquids (per bbl)	44.07	27.91	32.26	36.33	15.96	21.31
Natural gas (per Mcf)	3.01	3.04	3.03	3.13	2.82	2.89
Capital Expenditures						
Capital spending	$ 10.9	$ 105.9	$ 116.8	$ 10.2	$ 47.3	$ 57.5
Acquisitions	1.1	2.7	3.8	111.2	7.2	118.4
Divestments	0.9	0.5	1.4	(1.5)	(388.3)	(389.8)
Netback[3] **Before Hedging**						
Oil and natural gas sales	$ 64.9	$ 275.2	$ 340.1	$ 78.9	$ 189.7	$ 268.6
Royalties	(13.9)	(55.1)	(69.0)	(11.0)	(40.1)	(51.1)
Production taxes	(0.7)	(17.1)	(17.8)	(0.4)	(10.6)	(11.0)
Cash operating expenses	(18.2)	(34.1)	(52.3)	(30.7)	(28.4)	(59.1)
Transportation costs	(2.9)	(23.3)	(26.2)	(3.2)	(25.0)	(28.2)
Netback before hedging	$ 29.2	$ 145.6	$ 174.8	$ 33.6	$ 85.6	$ 119.2
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 41.0	$ —	$ 41.0	$ 33.0	$ —	$ 33.0
General and administrative expense[4]	13.9	5.8	19.7	21.0	7.0	28.0
Current income tax recovery	—	(50.2)	(50.2)	—	(2.1)	(2.1)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.
(4) Includes share-based compensation.

Comparing the fourth quarter of 2017 with the same period in 2016:

- Average daily production was 88,590 BOE/day, essentially unchanged from 2016 despite the divestment of non-core Canadian assets throughout 2017 and our non-operated North Dakota properties late in 2016 with combined production of 12,700 BOE/day. The divested production was fully offset with strong well performance from our increased capital spending program in 2017.

- Our crude oil and natural gas liquids production increased to 53% of our total production mix in the fourth quarter of 2017 compared to 47% in the same period in 2016.

- Our U.S. production increased by 12% to 71,703 BOE/day from 63,977 BOE/day, despite the divestment of our non-operated North Dakota properties on December 30, 2016, with production of approximately 5,000 BOE/day.

- Capital spending increased to $116.8 million compared to $57.5 million in the fourth quarter of 2016. The majority of our capital investment in the fourth quarter was focused on our core areas, with spending of $85.0 million on our North Dakota crude oil properties, $15.2 million on our Marcellus natural gas properties, and $10.0 million on our Canadian crude oil waterflood properties.

- Operating expenses decreased to $52.1 million ($6.39/BOE) compared to $58.5 million ($7.15/BOE) in the fourth quarter of 2016 as a result of the divestment of higher operating cost Canadian properties throughout 2016 and 2017, offset by increased costs in the U.S. related to our higher liquids production.

- Cash general and administrative ("G&A") expenses decreased to $12.6 million ($1.55/BOE) compared to $13.4 million ($1.63/BOE) in 2016 due to continued cost savings initiatives and the impact of staff reductions with the continued divestment of non-core assets.

- We reported net income of $15.3 million in the fourth quarter of 2017 compared to net income of $840.3 million in the fourth quarter of 2016. Net income decreased by $825.0 million primarily due to a non-cash deferred tax expense of $70.6 million in the fourth quarter of 2017 compared to a deferred tax recovery of $567.8 million for the same period in 2016. Net income in the fourth quarter of 2016 also benefited from a gain of $339.4 million on the sale of our non-operated North Dakota properties.

- Adjusted funds flow increased to $199.6 million compared to $107.7 million in the fourth quarter of 2016. The increase in adjusted funds flow was a result of an AMT recovery of $50.1 million, higher realized commodity prices, and the combined impact of lower operating costs, lower G&A expenses, and lower interest charges.

2017 OVERVIEW AND 2018 OUTLOOK

Summary of Guidance and Results	Revised 2017 Guidance	2017 Results	2018 Guidance
Capital spending ($ millions)	$450	$458	$535 - 585
Average annual production (BOE/day)	84,000	84,711	86,000 – 91,000
Crude oil and natural gas liquids volumes (bbls/day)	40,500	40,793	46,000 – 50,000
Average royalty and production tax rate (% of oil and natural gas sales)	24%	24%	25%
Operating expenses (per BOE)	$6.50	$6.37	$7.00
Transportation costs (per BOE)	$3.70	$3.60	$3.60
Cash G&A expenses (per BOE)	$1.70	$1.63	$1.65

2017 Overview

We reinitiated growth in 2017, delivering total production growth of 14% and liquids growth of 39%, as measured from the first quarter of 2017 through the fourth quarter of 2017, after adjusting for divestments. Notably, our North Dakota production increased 70% throughout 2017 with increased capital investment and strong operational performance. These results were achieved while maintaining our balance sheet strength.

In 2017, our annual average production was 84,711 BOE/day with crude oil and liquids volumes of 40,793 bbls/day, exceeding our guidance targets of 84,000 BOE/day and 40,500 bbls/day, respectively. Our capital spending for the year totaled $458.0 million, in line with our guidance of $450 million. The majority of our spending (87%) was focused on our liquids properties, primarily in North Dakota.

Our realized sales price differentials improved during the year with additional industry pipeline capacity coming online in the Bakken and Marcellus in 2017. Our Bakken differential narrowed by $3.74/bbl or 50%, and our Marcellus differential narrowed by $0.17/Mcf or 18% when compared to 2016.

Operating expenses and cash G&A expenses were $6.37/BOE and $1.63/BOE, respectively, beating our guidance of $6.50/BOE and $1.70/BOE, respectively. The outperformance was a result of our ongoing cost saving initiatives and our continued effort to focus our business through the sale of higher cost non-core assets.

Net income for 2017 was $237.0 million, a decrease from net income of $397.4 million in 2016 primarily due to lower realized gains on asset divestments and an increase in deferred tax expense due to both the impact of the changes in U.S. tax legislation announced late in 2017 and higher net income before taxes.

Adjusted funds flow increased 71% to $524.1 million from $305.6 million in 2016. This included a current tax recovery of $50.1 million for an AMT refund expected in 2018, as a result of new U.S. tax legislation. Net oil and gas sales also increased by $198.0 million largely due to higher realized commodity prices and narrower sales price differentials in both North Dakota and the Marcellus.

We continued to focus our portfolio during 2017, divesting higher operating cost properties with significant asset retirement liabilities. During the period, we divested of properties with associated production of approximately 7,700 BOE/day for $56.2 million in proceeds, and associated asset retirement obligations of $72.3 million.

Net debt at December 31, 2017 was $325.8 million, comprised of $672.3 million of senior notes less $346.5 million in cash. At December 31, 2017, we were undrawn on our $800 million senior unsecured bank credit facility and had a net debt to adjusted funds flow ratio of 0.6x.

2018 Outlook

Our focus in 2018 will be to continue to deliver sustainable and profitable growth and generate strong returns on capital, while maintaining our financial strength. We have increased our capital budget for 2018 to between $535 and $585 million, with the majority of capital being allocated to our North Dakota crude oil properties. With this further investment, we expect our production to grow 30% year-over-year in North Dakota, which is anticipated to contribute to our liquids production mix increasing to more than 55% of our total production in the second half of 2018.

Annual 2018 production is expected to average between 86,000 – 91,000 BOE/day, with crude oil and natural gas liquids production expected to average between 46,000 – 50,000 bbls/day. After adjusting for completed and announced divestments of non-core assets, we are targeting 2018 full year production growth of approximately 10% and liquids growth of approximately 20%, year-over-year.

We expect our Bakken and Marcellus sales price differentials to continue to improve in 2018 to approximately US$2.50/bbl below WTI and US$0.40/Mcf below NYMEX, respectively, as a result of the Dakota Access Pipeline being in service for a full year and further pipeline capacity additions planned for the Marcellus in 2018.

To support our 2018 capital program, we have increased our 2018 and 2019 crude oil hedging program to 65% and 61%, respectively, of our 2018 forecasted crude oil production, after royalties. We have also added natural gas hedges in 2018 for approximately 20% of our forecasted 2018 natural gas production, after royalties.

Operating expenses are expected to average approximately $7.00/BOE in 2018, modestly higher than 2017 levels as we expect to further increase our crude oil and liquids weighting throughout 2018. We expect 90% of our capital program will be directed to our crude oil assets, which have slightly higher operating cost metrics.

We expect cash G&A expenses and transportation costs for 2018 to average approximately $1.65/BOE and $3.60/BOE, respectively, consistent with 2017.

RESULTS OF OPERATIONS

Production

Average Daily Production Volumes	2017	2016	2015
Crude oil (bbls/day)	36,935	38,353	41,639
Natural gas liquids (bbls/day)	3,858	4,903	4,763
Natural gas (Mcf/day)	263,506	299,214	360,733
Total daily sales (BOE/day)	84,711	93,125	106,524

Production in 2017 averaged 84,711 BOE/day and crude oil and liquids production averaged 40,793 BOE/day, exceeding our revised guidance of 84,000 BOE/day and 40,500 bbls/day, respectively, due to strong operational performance in both North Dakota and the Marcellus.

Annual average production decreased by 9% or 8,414 bbls/day compared to the prior year primarily due to non-core asset divestments in Canada throughout 2017 with combined production of approximately 7,700 BOE/day and the sale of 5,000 BOE/day from our U.S. non-operated North Dakota properties, which closed on December 30, 2016. The impact of these asset sales was offset by growth in our operated U.S. crude oil production due to additional investment in our North Dakota assets.

Our U.S. production in 2017 was similar to 2016 as strong well performance from our capital program offset the sale of our non-operated North Dakota properties and price related production curtailments in the Marcellus during the year.

Canadian production volumes decreased 7,996 BOE/day or 29% compared to the prior year, largely due to non-core asset divestments throughout 2017, offset somewhat by additional production from our Ante Creek crude oil waterflood property acquired late in 2016.

Our crude oil and natural gas liquids production accounted for 48% of our total average daily production in 2017, compared to 46% in 2016 and 44% in 2015.

Production for 2016 averaged 93,125 BOE/day, a decrease of 13% from 2015. Production decreased primarily as a result of non-core Canadian natural gas divestments through the first three quarters of 2016, a reduced capital program with lower commodity prices, and the impact of price related production curtailments in the Marcellus.

2018 Guidance

We expect annual average production for 2018 of 86,000 – 91,000 BOE/day, including 46,000 – 50,000 bbls/day of crude oil and natural gas liquids. With an increased capital spending program of $535 - $585 million, we anticipate year-over-year production growth of 10% and liquids growth of 20%, after adjusting for divestments. This guidance includes the full year impact of our 2017 non-core divestments with associated production of approximately 7,700 BOE/day (66% natural gas), as well as the impact of expected first quarter 2018 divestments of certain non-core Canadian properties with production of approximately 600 BOE/day.

Pricing

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

Pricing (average for the period)		2017		2016		2015
Benchmarks						
WTI crude oil (US$/bbl)	$	50.95	$	43.32	$	48.80
AECO natural gas – monthly index ($/Mcf)		2.43		2.09		2.77
AECO natural gas – daily index ($/Mcf)		2.16		2.16		2.69
NYMEX natural gas – last day (US$/Mcf)		3.11		2.46		2.66
US/CDN average exchange rate		1.30		1.32		1.28
US/CDN period end exchange rate		1.26		1.34		1.38
Enerplus selling price(1)						
Crude oil ($/bbl)	$	58.69	$	44.84	$	48.43
Natural gas liquids ($/bbl)		30.01		15.29		18.06
Natural gas ($/Mcf)		3.21		2.06		2.15
Average benchmark differentials						
MSW Edmonton – WTI (US$/bbl)	$	(2.46)	$	(3.21)	$	(3.93)
WCS Hardisty – WTI (US$/bbl)		(11.98)		(13.84)		(13.52)
Transco Leidy monthly – NYMEX (US$/Mcf)		(0.96)		(1.15)		(1.52)
TGP Z4 300L monthly – NYMEX (US$/Mcf)		(1.03)		(1.21)		(1.58)
AECO monthly – NYMEX (US$/Mcf)		(1.26)		(0.89)		(0.50)
Enerplus realized differentials(1)						
Canada crude oil – WTI (US$/bbl)	$	(10.94)	$	(13.21)	$	(13.34)
Canada natural gas – NYMEX (US$/Mcf)		(0.62)		(0.80)		(0.44)
Bakken crude oil – WTI (US$/bbl)		(3.72)		(7.46)		(9.44)
Marcellus natural gas – NYMEX (US$/Mcf)		(0.76)		(0.93)		(1.37)

(1) Before transportation costs, royalties and commodity derivative instruments.

CRUDE OIL AND NATURAL GAS LIQUIDS

Benchmark WTI prices in 2017 increased by 18% to US$50.95/bbl compared to 2016 as the reduction of approximately 1.8 MMbbl per day of production in 2017 by the Organization of Petroleum Exporting Countries ("OPEC"), along with strong global crude oil demand, helped to reduce much of the crude oil inventory overhang that depressed prices in 2016. WTI prices ended 2017 near their peak for the last three years at US$64.73/bbl. Our 2017 realized crude oil price averaged $58.69/bbl, a 31% increase compared to 2016. The strengthening of regional differentials for our crude oil produced both in Canada and more notably in North Dakota and Montana, helped improve our realized price more than the improvement in the WTI benchmark year-over-year.

Our Bakken sales price differentials narrowed by 50% in 2017, averaging US$3.72/bbl below WTI, beating our guidance of US$4.00/bbl below WTI. The start-up of the Dakota Access Pipeline mid-year increased the demand for Bakken crude oil leading to a meaningful improvement in our sales price differential relative to WTI. We expect the strength in differentials to continue in 2018 and our 2018 Bakken crude oil differential to average approximately US$2.50/bbl below WTI.

Canadian crude prices also strengthened during 2017, with both heavy and light differentials improving slightly compared to the prior year. For 2018, Canadian crude differentials are expected to trade significantly wider than what was realized in 2017 due to industry production exceeding regional demand and export pipeline capacity.

We realized an average of $30.01/bbl on our NGL production in 2017, an increase of 96% when compared to 2016. Benchmark pricing for NGL's improved dramatically in 2017 due to improving market fundamentals, particularly in the propane markets with increased exports offshore in the U.S.

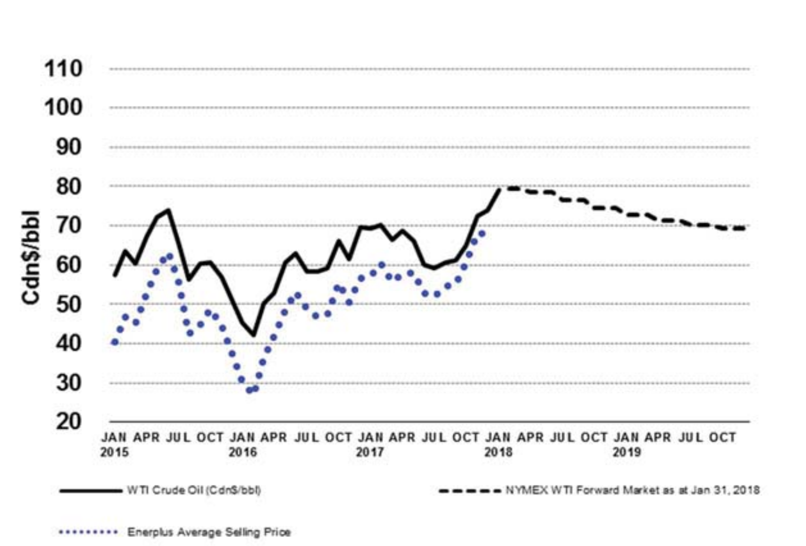
NATURAL GAS

Our realized natural gas price averaged $3.21/Mcf in 2017, a 56% increase from 2016 realized prices, and significantly higher than the 26% increase in the NYMEX benchmark price and the 16% increase in the AECO monthly benchmark price compared to 2016. Our realized natural gas price outperformed the benchmark changes year-over-year due to stronger Marcellus basis differentials in 2017 and the positive impact of our multi-year term AECO physical sales which carry average fixed basis differentials of US$0.65/Mcf below NYMEX.

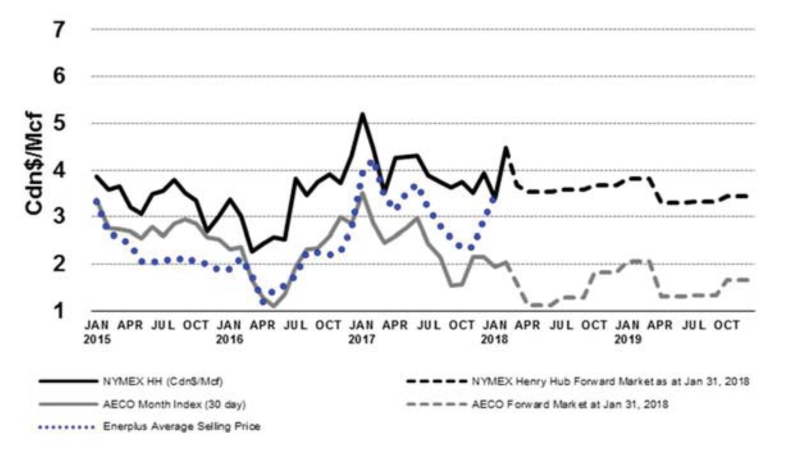
In the Marcellus, the Tennessee Gas Pipeline Zone 4 - 300 Leg and Transco Leidy monthly benchmark differentials averaged US$1.03/Mcf and US$0.96/Mcf below NYMEX compared to US$1.21/Mcf and US$1.15/Mcf below NYMEX in 2016. The strengthening in local Marcellus prices was due to additional pipeline capacity coming into service, as well as higher weather-related demand in the region. Our realized portfolio sales price continues to benefit from a transportation contract where 30,000 Mcf/day of our production is priced at markets south of the Marcellus producing region, allowing us to realize sales prices closer to NYMEX pricing. This contributed to an average Marcellus realized sales price differential, before transportation costs, of US$0.76/Mcf below NYMEX for the year, better than our guidance of US$0.80/Mcf below NYMEX, and an 18% improvement from 2016. We expect our Marcellus natural gas realized differential to average US$0.40/Mcf below NYMEX in 2018 due to additional industry pipeline capacity planned to come on-stream in the year.

In Alberta, congestion on regional and export pipelines and continued industry production growth resulted in benchmark AECO monthly prices averaging US$1.26/Mcf below NYMEX in 2017 compared to US$0.89/Mcf below NYMEX in 2016. Our term AECO physical sales portfolio at prices much stronger than benchmark averages protected all of our western Canadian gas production from this significant price weakness throughout 2017, and will continue to do so during 2018 and 2019.

Monthly Crude Oil Prices



Monthly Natural Gas Prices



FOREIGN EXCHANGE

The Canadian dollar strengthened throughout 2017 averaging 1.30 USD/CDN and closing the year at 1.26 USD/CDN compared to 1.34 USD/CDN at December 31, 2016. The improvement was driven primarily by signs of a strengthening Canadian economy and a series of increases in the Bank of Canada interest rates. The majority of our oil and natural gas sales are based on U.S. dollar denominated indices, and a stronger Canadian dollar relative to the U.S. dollar decreases the amount of our realized sales. Because we report in Canadian dollars, the stronger Canadian dollar also decreases our U.S. dollar denominated costs, capital spending and the interest cost of our U.S. dollar denominated senior notes.

Monthly USD/CDN Exchange Rate

Price Risk Management

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

As of February 20, 2018, we have hedged approximately 20,838 bbls/day of our crude oil production for 2018, which represents approximately 65% of our forecasted 2018 crude oil production, after royalties. For 2019, we have hedged 19,753 bbls/day, which represents approximately 61% of our crude oil production after royalties, based on the 2018 forecast. Our crude oil hedges are predominantly three way collars, which consist of a sold put, a purchased put and a sold call. When WTI prices settle below the sold put strike in any given month, the three way collars provide a limited amount of protection above the WTI index prices equal to the difference between the strike price of the purchased and sold puts. Overall, we continue to expect our crude oil hedge contracts to protect project economics and a significant portion of our adjusted funds flow.

As of February 20, 2018, we have hedged approximately 35,863 Mcf/day of our natural gas production for 2018 using NYMEX collars, which represents approximately 20% of our 2018 forecasted natural gas production, after royalties.

The following is a summary of our financial contracts in place at February 20, 2018, expressed as a percentage of our anticipated production volumes after royalties, using the midpoint of our guidance range, for 2018:

	WTI Crude Oil (US$/bbl)[1]						
	Jan 1, 2018 – Jan 31, 2018	Feb 1, 2018 – Mar 31, 2018	Apr 1, 2018 – Jun 30, 2018	Jul 1, 2018 – Sep 30, 2018	Oct 1, 2018 – Dec 31, 2018	Jan 1, 2019 – Mar 31, 2019	Apr 1, 2019 – Dec 31, 2019
Swaps							
Sold Swaps	$ 55.38	$ 58.32	$ 55.38	$ 53.73	$ 53.73	$ 53.73	-
%	16%	22%	16%	9%	9%	9%	-
Three Way Collars							
Sold Puts	$ 42.83	$ 42.83	$ 42.92	$ 42.71	$ 42.74	$ 44.05	$ 44.09
%	40%	40%	46%	56%	62%	50%	62%
Purchased Puts	$ 53.04	$ 53.04	$ 52.90	$ 52.53	$ 52.48	$ 53.69	$ 53.94
%	40%	40%	46%	56%	62%	50%	62%
Sold Calls	$ 61.99	$ 61.99	$ 61.73	$ 61.22	$ 61.10	$ 63.44	$ 63.84
%	40%	40%	46%	56%	62%	50%	62%

(1) Based on weighted average price (before premiums) assuming average annual production of 88,500 BOE/day for 2018 (at the mid-point of our guidance range), less royalties and production taxes of 25%.

	NYMEX Natural Gas (US$/Mcf)[1]		
	Jan 1, 2018 – Mar 31, 2018	Apr 1, 2018 – Oct 31, 2018	Nov 1, 2018 – Dec 31, 2018
Collars			
Purchased Puts	$ 2.75	$ 2.75	$ 2.75
%	16%	22%	16%
Sold Calls	$ 3.47	$ 3.38	$ 3.47
%	16%	22%	16%

(1) Based on weighted average price (before premiums) assuming average annual production of 88,500 BOE/day for 2018 (at the mid-point of our guidance range), less royalties and production taxes of 25%.

We did not have any foreign exchange contracts in place during 2017 and 2016. In comparison, during 2015, we recorded realized foreign exchange losses of $39.2 million on foreign exchange costless collars and foreign exchange gains of $39.9 million and $3.3 million, on the unwind of our US$175 million foreign exchange swap and the final settlement of the foreign exchange swap on our US$54 million senior notes, respectively.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)

($ millions)	2017	2016	2015
Cash gains/(losses):			
Crude oil	$ 0.9	$ 75.0	$ 217.2
Natural gas	7.7	5.3	70.5
Total cash gains	$ 8.6	$ 80.3	$ 287.7
Non-cash gains/(losses):			
Crude oil	$ (5.4)	$ (96.2)	$ (99.8)
Natural gas	11.1	(13.5)	(45.2)
Total non-cash gains/(losses)	$ 5.7	$ (109.7)	$ (145.0)
Total gains/(losses)	$ 14.3	$ (29.4)	$ 142.7

(Per BOE)	2017	2016	2015
Total cash gains/(losses)	$ 0.28	$ 2.36	$ 7.40
Total non-cash gains/(losses)	0.18	(3.22)	(3.73)
Total gains/(losses)	$ 0.46	$ (0.86)	$ 3.67

During 2017, we realized cash gains of $0.9 million on our crude oil contracts and $7.7 million on our natural gas contracts. Cash gains recorded on our natural gas contracts included a gain of $8.5 million on the unwind of a portion of our AECO-NYMEX basis physical contracts in conjunction with the sale of our Canadian non-core natural gas properties. In comparison, in 2016 we realized cash gains of $75.0 million on our crude oil contracts and $5.3 million on our natural gas contracts. During 2015, we realized cash gains of $217.2 million on our crude oil contracts and $70.5 million on our natural gas contracts. The cash gains in each year were due to contracts which provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. The fair value of our crude oil contracts was a net liability position of $34.3 million, while the fair value of our natural gas contracts was a net asset position of $1.7 million, at December 31, 2017 (December 31, 2016 – net loss positions of $28.8 million and $9.5 million, respectively). The change in fair value of our crude oil and natural gas contracts represented losses of $5.4 million and gains of $11.1 million, respectively, during 2017 and losses of $96.2 million and $13.5 million, respectively, during 2016.

Revenues

($ millions)	2017	2016	2015
Oil and natural gas sales	$ 1,141.8	$ 882.1	$ 1,052.4
Royalties	(221.1)	(159.4)	(168.0)
Oil and natural gas sales, net of royalties	$ 920.7	$ 722.7	$ 884.4

Oil and natural gas sales revenue for 2017 totaled $1,141.8 million, an increase of 29% from $882.1 million in 2016. The increase in revenue was a result of the improvement in commodity prices and realized sales price differentials compared to the prior year, along with a higher crude oil and natural gas liquids weighting of 48% compared to 46% in 2016.

In 2016, oil and natural gas sales revenue decreased 16% to $882.1 million from $1,052.4 million in 2015. The decrease was a result of the continued decline in commodity prices in 2016 compared to the prior year, along with lower production due to our non-core asset divestments and lower capital spending.

Royalties and Production Taxes

($ millions, except per BOE amounts)	2017	2016	2015
Royalties	$ 221.1	$ 159.4	$ 168.0
Per BOE	$ 7.15	$ 4.67	$ 4.32
Production taxes	$ 54.3	$ 37.4	$ 50.9
Per BOE	$ 1.76	$ 1.10	$ 1.31
Royalties and production taxes	$ 275.4	$ 196.8	$ 218.9
Per BOE	$ 8.91	$ 5.77	$ 5.63
Royalties and production taxes (% of oil and natural gas sales)	24%	22%	21%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. An increasing percentage of our production is from U.S. properties where royalty rates are generally higher and not as sensitive to commodity price levels.

Royalties and production taxes were in line with our revised guidance for 2017, averaging 24% of oil and natural gas sales, before transportation. Royalties and production taxes increased to $275.4 million in 2017 from $196.8 million in 2016 primarily due to an increase in realized crude oil and natural gas prices and higher production volumes coming from our U.S. properties with a combined royalty and production tax rate of 26%. In 2016, royalties and production taxes decreased to $196.8 million from $218.9 million in the prior year primarily due to lower production volumes, decreased realized crude oil and natural gas prices and 1.5% rate reduction for production taxes in North Dakota.

2018 Guidance

We expect royalty and production taxes in 2018 to average 25% of our oil and gas sales, before transportation. The increase compared to 2017 is due to the higher percentage of U.S. production volumes as a result of additional capital spending and growth in our U.S. assets.

Operating Expenses

($ millions, except per BOE amounts)	2017	2016	2015
Cash operating expenses	$ 197.7	$ 249.0	$ 340.1
Non-cash (gains)/losses[1]	(0.6)	(1.1)	0.4
Total operating expenses	$ 197.1	$ 247.9	$ 340.5
Per BOE	$ 6.37	$ 7.27	$ 8.76

(1) Non-cash (gains)/losses on fixed price electricity swaps.

Operating expenses during 2017 were $197.1 million or $6.37/BOE, beating our guidance of $6.50/BOE and representing a reduction of $50.8 million from the previous year. The decrease is mainly attributable to continued divestments of higher operating cost Canadian properties combined with our cost saving initiatives. This was partly offset by an increase in our crude oil and natural gas liquids production weighting, which has slightly higher associated operating cost metrics.

Operating expenses during 2016 were $247.9 million or $7.27/BOE compared to $340.5 million or $8.76/BOE in 2015. The improvement resulted mainly from cost savings, lower repairs and maintenance costs and the divestment of higher operating cost Canadian properties throughout the year.

2018 Guidance

We expect operating expenses of $7.00/BOE in 2018. The modest increase from 2017 is a result of the expected increase in the corporate weighting of our higher operating cost liquids production.

Transportation Costs

($ millions, except per BOE amounts)	2017	2016	2015
Transportation costs	$ 111.3	$ 107.1	$ 114.7
Per BOE	$ 3.60	$ 3.14	$ 2.95

Transportation costs in 2017 increased on a per BOE basis to average $3.60/BOE, beating our guidance of $3.70/BOE, and an increase from $3.14/BOE in 2016 and $2.95/BOE in 2015. Transportation costs have increased with growing U.S. production volumes which have higher associated transportation costs, as well as additional firm transportation commitments in the Marcellus that were incurred beginning in August of 2016.

2018 Guidance

We expect transportation costs to remain at $3.60/BOE in 2018, similar to 2017 levels.

Netbacks

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

	Year ended December 31, 2017		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	44,496 BOE/day	241,290 Mcfe/day	84,711 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 53.38	$ 3.12	$ 36.93
Royalties and production taxes	(13.89)	(0.57)	(8.91)
Cash operating expenses	(10.20)	(0.36)	(6.39)
Transportation costs	(2.21)	(0.86)	(3.60)
Netback before hedging	$ 27.08	$ 1.33	$ 18.03
Cash gains/(losses)	0.06	0.09	0.28
Netback after hedging	$ 27.14	$ 1.42	$ 18.31
Netback before hedging ($ millions)	$ 439.8	$ 117.6	$ 557.4
Netback after hedging ($ millions)	$ 440.7	$ 125.2	$ 566.0

(1) See “Non-GAAP Measures” in this MD&A.

Netbacks by Property Type	Year ended December 31, 2016 Crude Oil	Natural Gas	Total
Average Daily Production	47,206 BOE/day	275,538 Mcfe/day	93,125 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 37.86	$ 2.26	$ 25.88
Royalties and production taxes	(9.38)	(0.34)	(5.77)
Cash operating expenses	(10.29)	(0.72)	(7.31)
Transportation costs	(1.97)	(0.72)	(3.14)
Netback before hedging	$ 16.22	$ 0.48	$ 9.66
Cash gains/(losses)	4.34	0.05	2.36
Netback after hedging	$ 20.56	$ 0.53	$ 12.02
Netback before hedging ($ millions)	$ 280.4	$ 48.8	$ 329.2
Netback after hedging ($ millions)	$ 355.3	$ 54.2	$ 409.5

Netbacks by Property Type	Year ended December 31, 2015 Crude Oil	Natural Gas	Total
Average Daily Production	49,069 BOE/day	344,730 Mcfe/day	106,524 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales	$ 43.67	$ 2.15	$ 27.07
Royalties and production taxes	(10.54)	(0.24)	(5.63)
Cash operating expenses	(11.98)	(1.00)	(8.75)
Transportation costs	(1.84)	(0.65)	(2.95)
Netback before hedging	$ 19.31	$ 0.26	$ 9.74
Cash gains/(losses)	12.13	0.56	7.40
Netback after hedging	$ 31.44	$ 0.82	$ 17.14
Netback before hedging ($ millions)	$ 345.7	$ 33.0	$ 378.7
Netback after hedging ($ millions)	$ 562.9	$ 103.5	$ 666.4

(2) See “Non-GAAP Measures” in this MD&A.

Crude oil and natural gas netbacks per BOE before hedging were higher during 2017 compared to 2016 and 2015 primarily due to higher crude oil and natural gas prices, improvements in our sales price differentials in North Dakota and the Marcellus, as well as reductions to our operating expenses due in part to the sale of higher operating cost non-core Canadian assets. During 2017, our crude oil properties accounted for 79% and 78% of our netback before and after hedging, respectively.

General and Administrative Expenses

Total G&A expenses include cash G&A expenses and share-based compensation (“SBC”) charges related to our long-term incentive plans (“LTI plans”). See Note 10 and Note 13 to the Financial Statements for further details.

($ millions)	2017	2016	2015
Cash:			
G&A expense	$ 50.5	$ 59.8	$ 81.3
Share-based compensation expense	1.0	3.1	0.9
Non-Cash:			
Share-based compensation expense	22.6	27.0	19.6
Equity swap loss/(gain)	0.2	(3.6)	2.1
Total G&A expenses	$ 74.3	$ 86.3	$ 103.9

(Per BOE)	2017	2016	2015
Cash:			
G&A expense	$ 1.63	$ 1.75	$ 2.09
Share-based compensation expense	0.03	0.09	0.02
Non-Cash:			
Share-based compensation expense	0.73	0.80	0.51
Equity swap loss/(gain)	0.01	(0.11)	0.05
Total G&A expenses	$ 2.40	$ 2.53	$ 2.67

Cash G&A expenses in 2017 totaled $50.5 million ($1.63/BOE), beating our guidance of $1.70/BOE and representing a decrease of 16% from $59.8 million ($1.75/BOE) in 2016. The reduction in 2017 was primarily due to continued cost savings initiatives and the impact of reductions in staff levels throughout 2016 and 2017, as we continued to divest of non-core assets and focus our business.

During the year, we reported cash SBC of $1.0 million ($0.03/BOE), a decrease of 68% compared to $3.1 million ($0.09/BOE) in 2016 due to the settlement of the final grants of our cash-settled Restricted Share Unit ("RSU") plans in 2016. The Deferred Share Unit ("DSU") plan is our only remaining LTI plan that we intend to settle in cash. We recorded non-cash SBC of $22.6 million ($0.73/BOE) in 2017 compared to $27.0 million ($0.80/BOE) in 2016. The decrease in non-cash SBC was a result of the performance multipliers on our Performance Share Unit ("PSU") plans remaining unchanged from 2016.

Cash G&A expenses in 2016 were $59.8 million ($1.75/BOE), a decrease of 26% from $81.3 million ($2.09/BOE) in 2015. Cash SBC expense was $3.1 million ($0.09/BOE) in 2016 compared to an expense of $0.9 million ($0.02/BOE) in 2015. We recorded non-cash SBC of $27.0 million ($0.80/BOE) in 2016 compared to $19.6 million ($0.51/BOE) in 2015 due to an improvement in our performance multiplier, along with additional grants issued under the treasury-settled LTI plans.

We have hedged a portion of the outstanding cash-settled units under our LTI plans. We recorded a non-cash mark-to-market loss of $0.2 million on these hedges in 2017 (2016 – $3.6 million gain; 2015 – $2.1 million loss). As of December 31, 2017, we have 470,000 units hedged at a weighted average price of $16.89/share.

2018 Guidance

We expect our cash G&A expense to be $1.65/BOE in 2018, which is consistent with 2017.

Interest Expense

Interest on our senior notes and bank credit facility in 2017 totaled $38.7 million compared to $45.4 million in 2016 and $66.5 million in 2015. Interest expense decreased 15% in 2017 when compared to 2016 due to being undrawn on our bank credit facility, the impact of the strengthening Canadian dollar on our U.S. denominated interest payments, and the first of five annual principal instalments of US$22 million on our US$110 million 7.97% senior notes paid during the second quarter of 2017.

Interest expense decreased 32% in 2016 compared to 2015 with a reduction in the principal amount of our outstanding senior notes following the repurchase of US$267 million of senior notes during the first half of 2016.

At December 31, 2017, we were undrawn on our $800 million bank credit facility and our debt consisted of fixed interest rate senior notes with a weighted average interest rate of 4.8%. See Note 7 to the Financial Statements for further details on outstanding notes.

Foreign Exchange

($ millions)	2017	2016	2015
Realized:			
Foreign exchange (gain)/loss on settlements	$ 1.5	$ 0.1	$ (8.7)
Translation of U.S. dollar cash held in Canada (gain)/loss	11.0	—	—
Unrealized loss/(gain)	(42.6)	(40.6)	182.6
Total foreign exchange loss/(gain)	$ (30.1)	$ (40.5)	$ 173.9
US/CDN average exchange rate	1.30	1.32	1.28
US/CDN period end exchange rate	1.26	1.34	1.38

We recorded a net foreign exchange gain of $30.1 million in 2017 compared to gains of $40.5 million and losses of $173.9 million in 2016 and 2015, respectively. Realized gains and losses relate primarily to day-to-day transactions recorded in foreign currencies, along with the translation of our U.S. dollar denominated cash held in Canada, while unrealized gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period-end.

In 2017, we recorded a realized foreign exchange loss of $12.5 million, due to the strengthening of the Canadian dollar compared to a loss of $0.1 million in 2016. In 2015, the realized foreign exchange gain of $8.7 million included a gain of $39.9 million on the unwind of our US$175 million foreign exchange swaps and a gain of $3.3 million on the final settlement of our US$54 million senior notes and the corresponding foreign exchange swap. These gains were offset by cumulative losses of $39.2 million on our foreign exchange collars with final settlements in December 2015.

Unrealized foreign exchange gains and losses are recorded on the translation of our U.S. dollar denominated debt and working capital at each period end. Comparing December 31, 2017 to December 31, 2016, the Canadian dollar strengthened relative to the U.S. dollar, resulting in an unrealized gain of $42.6 million. See Note 11 to the Financial Statements for further details.

Capital Investment

($ millions)	2017	2016	2015
Capital spending	$ 458.0	$ 209.1	$ 493.4
Office capital	2.7	1.5	4.5
Sub-total	460.7	210.6	497.9
Property and land acquisitions	$ 13.3	$ 126.1	$ 9.5
Property divestments	(56.2)	(670.4)	(286.6)
Sub-total	(42.9)	(544.3)	(277.1)
Total[(1)]	$ 417.8	$ (333.7)	$ 220.8

(1) Excludes changes in non-cash investing working capital. See Note 17(b) of the Consolidated Financial Statements for additional information.

2017

Capital spending in 2017 totaled $458.0 million, in line with our guidance of $450 million. Our capital spending in 2017 was more than twice our spending levels in 2016, as we repositioned ourselves for growth. In 2017 we spent $343.0 million on our U.S. crude oil properties, $55.3 million on our Canadian crude oil properties, and $58.5 million on our Marcellus natural gas assets. In 2017, we added 58.0 MMBOE of gross proved plus probable reserves, replacing 189% of our 2017 production, before accounting for acquisitions and divestments.

We recorded net divestment proceeds of $56.2 million in 2017 consisting mainly of our second quarter sale of our Brooks waterflood property and Canadian shallow gas assets. Total divestments had combined production of 7,700 BOE/day and resulted in a $72.3 million reduction to future asset retirement obligations. Property and land acquisitions in 2017 totaled $13.3 million and included additional leases and minor undeveloped land.

2016

Capital spending in 2016 totaled $209.1 million, and was focused on our core areas with spending of $136.4 million on our North Dakota crude oil properties, $44.4 million on our Canadian crude oil waterflood properties and $24.3 million on our Marcellus natural gas assets.

We recorded net divestment proceeds of $670.4 million in 2016. In Canada, we sold properties consisting mainly of natural gas assets, which included certain Deep Basin natural gas properties and non-core properties in northwest Alberta with combined production of approximately 8,500 BOE/day. On December 30, 2016, we closed the sale of our non-operated assets in North Dakota with production of approximately 5,000 BOE/day for proceeds of $392.0 million, which was reported as restricted cash at December 31, 2016. Through our capital program in 2016 we added 43 MMBOE of gross proved plus probable reserves, replacing 126% of our 2016 production, before accounting for acquisitions and divestments.

Property and land acquisitions in 2016 totaled $126.1 million, largely due to our acquisition of a Canadian waterflood property for a purchase price of $110.3 million, net of closing adjustments.

2015

Capital spending in 2015 totaled $493.4 million and included spending of $302.3 million on our North Dakota crude oil properties, $115.7 million on our Canadian crude oil properties, $32.2 million on our Marcellus assets and $40.4 million on our Deep Basin properties in Canada. Through our capital program in 2015 we added 42 MMBOE of gross proved plus probable reserves, replacing 108% of our 2015 production, before accounting for acquisitions and divestments.

During 2015, we recorded net divestment proceeds of $286.6 million. In Canada, we divested of assets for combined proceeds of $198.9 million with production of approximately 4,900 BOE/day including the sale of our Pembina waterflood assets and certain non-core shallow gas assets with production of 2,700 BOE/day. In the U.S., we divested of assets for combined proceeds of $87.7 million with production of approximately 1,250 BOE/day, including the sale of a portion of our non-operated North Dakota properties for proceeds of $80.4 million, and our operated Marcellus assets for proceeds of $3.5 million. Property and land acquisitions in 2015 totaled $9.5 million and included minor acquisitions of leases and undeveloped land.

2018 Guidance

To deliver on our production and liquids growth targets of 10% and 20%, respectively, net of divestments, we are increasing our capital spending guidance for 2018 to $535 to $585 million, a 22% increase from 2017. Our spending is focused on our core areas, with approximately $420 million allocated to North Dakota, $60 million to our Marcellus gas properties and $60 million to our Canadian crude oil waterflood properties.

Gain on Asset Sales and Note Repurchases

We recorded gains of $78.4 million during 2017 related to the divestment of our Brooks waterflood property and Canadian shallow gas assets. In 2016, a gain of $559.2 million was recorded on asset divestments, which included a gain of $339.4 million on the fourth quarter sale of our non-operated North Dakota property. No gains were recorded on asset sales in 2015. Under full cost accounting rules, divestments of oil and natural gas properties are generally accounted for as adjustments to the full cost pool with no recognition of a gain or loss. However, if not recognizing a gain or loss on the transaction would significantly alter the relationship between a cost centre's capitalized costs and proved reserves, then a gain or loss must be recognized. Gains and losses are evaluated on a case by case basis for each asset sale, and future sales may or may not result in such treatment.

During 2017 we did not repurchase any of our senior notes. During the first half of 2016, we recorded a total gain of $19.3 million on the repurchase of US$267 million of outstanding senior notes at prices between 90% of par and par value.

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

($ millions, except per BOE amounts)	2017	2016	2015
DD&A expense	$ 250.8	$ 329.0	$ 508.2
Per BOE	$ 8.11	$ 9.65	$ 13.06

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. DD&A in 2017 decreased from 2016 mainly due to an increased weighting of U.S. production with lower depletion rates along with reserve additions for the year and the impact of the 2016 asset impairments. In 2016, DD&A decreased from the prior year mostly due to asset impairments recorded during 2016 and 2015 under the U.S. GAAP full cost ceiling test methodology.

Impairments

PP&E

($ millions)	2017	2016	2015
Canada cost centre	$ —	$ 89.4	$ 286.7
U.S. cost centre	—	211.8	1,065.7
Total Impairments	$ —	$ 301.2	$ 1,352.4

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

The trailing twelve month average crude oil and natural gas prices have improved throughout 2017 and no impairments were recorded. In comparison, trailing twelve month average commodity prices weakened significantly in 2016 and 2015, resulting in non-cash impairments totaling $301.2 million and $1,352.4 million (before taxes), respectively.

The following table outlines the twelve month average trailing benchmark prices and exchange rates used in our ceiling test at December 31, 2017, 2016 and 2015:

Year	WTI Crude Oil US$/bbl	Exchange Rate US/CDN	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	AECO Natural Gas Spot CDN$/Mcf
2017	$ 51.34	1.30	$ 63.57	$ 2.98	$ 2.32
2016	$ 42.75	1.32	$ 52.26	$ 2.49	$ 2.17
2015	$ 50.28	1.27	$ 59.38	$ 2.58	$ 2.69

Many factors influence the allowed ceiling value versus our net capitalized cost base, making it difficult to predict with reasonable certainty the value of impairment losses from future ceiling tests. For the next year, the primary factors include future first-day-of-the-month commodity prices, reserves revisions, our capital expenditure levels and timing, acquisition and divestment activity, as well as production levels, which affect DD&A expense. Although the twelve month average trailing commodity prices are below current levels, there is the potential for prices to decline, impacting the ceiling value which could result in further non-cash impairments.

Goodwill

Goodwill impairment testing is performed annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. We perform a qualitative assessment of goodwill by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value we perform quantitative impairment tests. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss) in the Financial Statements.

Our annual goodwill impairment assessments at December 31, 2017 and 2016 resulted in no impairment.

Asset Retirement Obligation

In connection with our operations, we incur abandonment and reclamation costs related to assets, such as surface leases, wells, facilities and pipelines. Total asset retirement obligations included on our balance sheet are based on management's estimate of our net ownership interest, costs to abandon and reclaim and the timing of the costs to be incurred in future periods.

We have estimated the net present value of our asset retirement obligation to be $117.7 million at December 31, 2017, compared to $181.7 million at December 31, 2016. The decrease was largely due to the removal of $72.3 million or 40% of our asset retirement obligations which were related to asset divestments during 2017. See Note 8 to the Financial Statements for further information.

We take an active approach to managing our abandonment, reclamation and remediation obligations. During 2017, we spent $12.9 million (2016 – $8.4 million) on our asset retirement obligations and we expect to spend approximately $10.0 million in 2018. The majority of our abandonment and reclamation costs are expected to be incurred between 2025 and 2055. We do not reserve cash or assets for the purpose of funding our future asset retirement obligations. Any abandonment and reclamation costs are anticipated to be funded out of cash flow and available credit facilities.

Income Taxes

($ millions)	2017	2016	2015
Current tax expense/(recovery)	$ (48.0)	$ (2.4)	$ (16.9)
Deferred tax expense/(recovery)	129.9	(234.8)	(150.6)
Total tax expense/(recovery)	$ 81.9	$ (237.2)	$ (167.5)

The total tax expense for 2017 includes the impact of the enactment of the U.S. Tax Cuts and Jobs Act ("Tax Legislation") on December 22, 2017. The Tax Legislation significantly modified the existing U.S. tax law including the reduction of the federal income tax rate to 21% from 35%, the repeal of corporate AMT and the ultimate refund of existing AMT credit carryovers. While most of these changes are effective January 1, 2018 and will positively impact our future after-tax earnings, we are required to recognize certain changes in income tax expense in 2017 as outlined below.

Our current tax recovery primarily relates to the reclassification of $50.1 million to income tax receivable from our deferred income tax asset for the portion of our AMT refund expected to be realized in 2018. The remaining $50.1 million in AMT refund is expected to be realized over the years 2019 to 2021.

The total tax expense in 2017 was $81.9 million compared to a $237.2 million total tax recovery in 2016. The recovery in 2016 was primarily due to the removal of a significant portion of our valuation allowance in both Canada and the U.S. due to higher projected future taxable income in both jurisdictions. In 2017, deferred tax expense includes $46.2 million from the remeasurement of our U.S. deferred income tax assets for the federal income tax rate reduction, net of the reversal of the valuation allowance previously recorded on our AMT credit carryovers. We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not all or a portion of our deferred income tax assets will be realized. We consider available positive and negative evidence including future taxable income and reversing existing temporary differences in making this assessment. Our overall deferred income tax asset, net of valuation allowance, is $569.9 million at December 31, 2017 (2016 - $733.4 million). Our remaining valuation allowance is related to our net capital loss carryforward balance, as we do not anticipate future capital gains that will allow us to utilize these losses.

Our estimated tax pools at December 31, 2017 are as follows:

Pool Type ($ millions)	**2017**
Canada	
Canadian development expenditures (“CDE”)	$ 51
Canadian exploration expenditures (“CEE”)	237
Undepreciated capital costs (“UCC”)	121
Non-capital losses and other credits	414
	$ 823
U.S.	
Alternative minimum tax credit (“AMT”)	$ 100
Net operating losses	854
Depletable and depreciable assets	985
	$ 1,939
Total tax pools and credits	$ 2,762
Capital losses	$ 1,223

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a maximum senior debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges (“adjusted EBITDA”) ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. Our senior debt to adjusted EBITDA ratio increased to 1.2x at December 31, 2017 from 0.8x at December 31, 2016 as a result of a decrease in our trailing twelve month EBITDA, which benefited from significant gains recognized in 2016 on asset divestments and the repurchase of senior notes. Our net debt to adjusted funds flow ratio decreased to 0.6x at December 31, 2017 from 1.2x at December 31, 2016 as a result of the significant increase in our adjusted funds flow in 2017. Although it is not included in our debt covenants, the net debt to adjusted funds flow ratio is often used by investors and analysts to evaluate our liquidity.

We continued to strengthen our financial position in 2017, reducing our net debt by 13% over the twelve month period. Asset divestments throughout 2017 resulted in aggregate divestment proceeds of $56.2 million. This additional liquidity was used to fully repay our bank credit facility and to repay the first of five principal instalments of US$22 million on our US$110 million, 7.97% senior notes.

Total debt, net of cash and restricted cash, at December 31, 2017 was $325.8 million compared to $375.5 million at December 31, 2016. Total debt was comprised of $672.3 million in senior notes less $346.5 million in cash. Our next scheduled senior notes repayment of US$22 million is due in June 2018 with remaining maturities extending to 2026. At December 31, 2017, we were undrawn on our $800 million bank facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by adjusted funds flow, was 93% for 2017 compared to 80% in 2016. After adjusting for net acquisition and divestment proceeds, our funding surplus for the year ended December 31, 2017 was $77.2 million compared to $603.8 million in 2016. We expect to continue to pay monthly dividends to our shareholders of $0.01 per share, however, if economic conditions change we may make adjustments.

Our working capital deficiency, excluding cash, restricted cash and current derivative assets and liabilities, increased to $107.6 million at December 31, 2017 from $94.4 million at December 31, 2016. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, adjusted funds flow and our bank credit facility. In addition, we have sufficient liquidity to meet our financial commitments for the near term, as disclosed under “Commitments” below.

During the fourth quarter, we completed a one year extension of our $800 million senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2020. There were no other amendments to the agreement terms or debt covenants. Drawn fees on our bank credit facility range between 150 and 315 basis points over Banker’s Acceptance rates, with current drawn fees of 150 basis points. The bank credit facility ranks equally with our senior unsecured covenant-based notes.

At December 31, 2017 we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants at December 31, 2017:

Covenant Description		December 31, 2017
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA	3.5x	1.2x
Total debt to adjusted EBITDA	4.0x	1.2x
Total debt to capitalization	50%	21%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA[(1)]	3.0x – 3.5x	1.2x
Senior debt to consolidated present value of total proved reserves[(2)]	60%	25%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0x	14.7x

Definitions

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

"EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion and non-cash gains and losses. EBITDA is calculated on a trailing twelve month basis and is adjusted for material acquisitions and divestments. EBITDA for the three months and the trailing twelve months ended December 31, 2017 were $161.6 million and $570.0 million, respectively.

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

"Capitalization" is calculated as the sum of total debt and shareholder's equity plus a $1.1 billion adjustment related to our adoption of U.S. GAAP.

Footnotes

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

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

Counterparty Credit

OIL AND NATURAL GAS SALES COUNTERPARTIES

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

FINANCIAL DERIVATIVE COUNTERPARTIES

We are exposed to credit risk in the event of non-performance by our financial counterparties regarding our derivative contracts. We mitigate this risk by entering into transactions with major financial institutions, the majority of which are members of our bank syndicate. We have International Swaps and Derivatives Association ("ISDA") agreements in place with the great majority of our financial counterparties. These agreements provide some credit protection by generally allowing parties to aggregate amounts owing to each other under all outstanding transactions and settle with a single net amount in the case of a credit event. To date we have not experienced any losses due to non-performance by our derivative counterparties. All of our derivative counterparties are considered investment grade. At December 31, 2017, we had $3.9 million in mark-to-market assets offset by $38.5 million of mark-to-market liabilities resulting in a net liability position of $34.6 million.

Dividends

($ millions, except per share amounts)	2017	2016	2015
Cash dividends	$ 29.0	$ 35.4	$ 132.0
Per weighted average share (Basic)	$ 0.12	$ 0.16	$ 0.64

We reported total dividends of $29.0 million or $0.12 per share to our shareholders in 2017. During 2016 and 2015, we reported total dividends of $35.4 million or $0.16 per share and $132.0 million or $0.64 per share, respectively. Dividends for 2017 represented approximately 6% of adjusted funds flow, compared to approximately 12% in 2016 and 27% in 2015.

Effective with our April 2016 dividend, we reduced our monthly dividend to $0.01 per share. During 2015, we reduced our monthly dividend twice, from $0.09 per share to $0.05 per share in April and to $0.03 per share in December.

The dividend is part of our strategy to create shareholder value; however, a sustained low price environment may impact our ability to pay dividends. We continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	2017	2016	2015
Share capital ($ millions)	$ 3,386.9	$ 3,366.0	$ 3,133.5
Common shares outstanding (thousands)	242,129	240,483	206,539
Weighted average shares outstanding – basic (thousands)	241,929	226,530	206,205
Weighted average shares outstanding – diluted (thousands)	247,874	231,293	206,205

During 2017, a total of 1,646,000 shares (2016 – 594,000; 2015 – 807,000) and $21.0 million of additional equity (2016 – $9.4 million; 2015 – $13.3 million) was issued pursuant to the treasury-settled LTI plans. For further details see Note 13 to the Financial Statements.

On May 31, 2016, 33,350,000 common shares were issued at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million, net of issue costs before tax).

At February 22, 2018, we had 243,602,915 shares outstanding. In addition, an aggregate of 11,538,849 common shares may be issued to settle outstanding grants under the PSU, RSU, and stock option plans, assuming the maximum payout multiplier of 2.0 times for the PSUs.

Commitments

At December 31, 2017 we had the following minimum annual commitments:

		Minimum Annual Commitment Each Year					Total Committed
($ millions)	Total	2018	2019	2020	2021	2022	after 2022
Senior notes[1]	$ 672.4	$ 27.7	$ 57.7	$ 102.6	$ 102.6	$ 126.4	$ 255.4
Transportation commitments	249.2	28.1	26.5	22.7	19.8	17.7	134.4
Processing commitments	26.3	10.1	3.5	3.2	1.5	1.5	6.5
Drilling and completions	66.1	50.9	7.6	7.6	—	—	—
Office lease commitments	74.9	11.8	10.5	10.6	10.7	10.7	20.6
Sublease recoveries	(16.7)	(3.0)	(3.3)	(3.1)	(3.0)	(1.9)	(2.4)
Net office lease commitments	58.2	8.8	7.2	7.5	7.7	8.8	18.2
Total commitments[2][3]	$ 1,072.2	$ 125.6	$ 102.5	$ 143.6	$ 131.6	$ 154.4	$ 414.5

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) US$ commitments have been converted to CDN$ using the December 31, 2017 foreign exchange rate of 1.2571.

In the Marcellus, we have firm transportation agreements in place for approximately 66,000 Mcf/day, which expire between 2020 and 2036. This includes the agreement for additional interstate pipeline capacity on the Tennessee Gas Pipeline from our Marcellus producing region to downstream connections that became effective in August 2016. Under this agreement, we are committed to a US$0.63/Mcf demand toll for 30,000 Mcf/day of natural gas until mid-2027, reducing to 15,000 Mcf/day for an additional 9 years, with a total estimated transportation commitment of $122.4 million extending to 2036. We have also entered into a binding contract for five years of firm transportation capacity for 30,000 Mcf/day on the PennEast pipeline project. This project has been approved by the Federal Energy Regulatory Commission, however it is currently awaiting state level approvals with an expected in-service date of 2019.

In Canada, we have various firm transportation agreements for approximately 3,200 BOE/day of our crude oil and natural gas liquids production in 2018, decreasing to approximately 1,600 BOE/day on average from 2019 to 2027. We also have firm natural gas transportation contracts in 2018 for approximately 69,000 Mcf/day. At December 31, 2017, we have firm natural gas liquids fractionation contracts for 1,125 BOE/day through 2027.

Our Canadian office lease is committed to 2024 and our U.S. office lease expires in 2019. Annual costs of these lease commitments include rent and operating fees. Our office lease commitments are shown net of sublease agreements, which we entered into to reduce our obligations.

Our commitments and contingencies are more fully described in Note 15 to the Financial Statements.

SELECTED ANNUAL CANADIAN AND U.S. FINANCIAL RESULTS

	Year ended December 31, 2017			Year ended December 31, 2016		
(millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	10,779	26,156	36,935	13,089	25,264	38,353
Natural gas liquids (bbls/day)	1,193	2,665	3,858	1,408	3,495	4,903
Natural gas (Mcf/day)	46,228	217,278	263,506	79,057	220,157	299,214
Total average daily production (BOE/day)	19,677	65,034	84,711	27,673	65,452	93,125
Pricing[2]						
Crude oil (per bbl)	$ 51.87	$ 61.50	$ 58.69	$ 39.91	$ 47.39	$ 44.84
Natural gas liquids (per bbl)	38.13	26.38	30.01	27.52	10.36	15.29
Natural gas (per Mcf)	3.30	3.19	3.21	2.20	2.00	2.06
Capital Expenditures						
Capital spending	$ 56.5	$ 401.5	$ 458.0	$ 44.4	$ 164.7	$ 209.1
Acquisitions	4.7	8.6	13.3	114.4	11.7	126.1
Divestments	(56.6)	0.4	(56.2)	(281.0)	(389.4)	(670.4)
Netback[3] Before Hedging						
Oil and natural gas sales	$ 276.3	$ 865.5	$ 1,141.8	$ 269.2	$ 612.9	$ 882.1
Royalties	(49.3)	(171.8)	(221.1)	(35.8)	(123.6)	(159.4)
Production taxes	(3.3)	(51.0)	(54.3)	(2.5)	(34.9)	(37.4)
Cash operating expenses	(82.1)	(115.6)	(197.7)	(135.7)	(113.3)	(249.0)
Transportation costs	(13.3)	(98.0)	(111.3)	(14.0)	(93.1)	(107.1)
Netback before hedging	$ 128.3	$ 429.1	$ 557.4	$ 81.2	$ 248.0	$ 329.2
Other Expenses						
Commodity derivative instruments loss/(gain)[4]	$ (14.3)	$ —	$ (14.3)	$ 29.4	$ —	$ 29.4
General and administrative expense[5]	48.9	25.4	74.3	63.9	22.4	86.3
Current income tax expense/(recovery)	(0.4)	(47.6)	(48.0)	(0.7)	(1.7)	(2.4)

(1) Company interest volumes.
(2) Before transportation costs, royalties and the effects of commodity derivative instruments.
(3) See "Non-GAAP Measures" section in this MD&A.
(4) Includes realized and unrealized gains and losses on commodity derivative instruments.
(5) Includes share-based compensation.

THREE YEAR SUMMARY OF KEY MEASURES

($ millions, except per share amounts)	2017	2016	2015
Oil and natural gas sales, net of royalties	$ 920.7	$ 722.7	$ 884.4
Net income/(loss)	237.0	397.4	(1,523.4)
Per share (Basic)	0.98	1.75	(7.39)
Per share (Diluted)	0.96	1.72	(7.39)
Adjusted funds flow[1]	524.1	305.6	493.1
Cash dividends[2]	29.0	35.4	132.0
Per share (Basic)[2]	0.12	0.16	0.64
Total assets	2,645.8	2,638.9	2,581.2
Long-term debt, net of cash and restricted cash	325.8	375.5	1,216.2

(1) See "Non-GAAP Measures" section of this MD&A.
(2) Calculated based on dividends paid or payable. Cash dividends to shareholders per share may not correspond to actual dividends as a result of using the annual weighted average shares outstanding.

2017 versus 2016

Net oil and natural gas sales were $920.7 million in 2017 compared to $722.7 million in 2016 due to higher realized commodity prices, offset by the impact of lower production volumes as a result of our asset divestments over that period.

We reported net income of $237.0 million in 2017 compared to $397.4 million in 2016. The decrease in 2017 was primarily due to a $480.8 million decrease in gains being recorded on the divestment of assets during the period and a gain recorded in 2016 for $19.3 million related to the prepayment of senior notes. We also recorded a deferred tax expense of $129.9 million in 2017 compared to a deferred tax recovery of $234.8 million in 2016, due to higher net income before taxes and the impact of the U.S. Tax Legislation on our U.S. deferred income tax assets.

Adjusted funds flow increased 71% to $524.1 million in 2017 from $305.6 million in 2016. The increase was mainly due to a $198.0 million increase in net oil and gas natural gas sales, a $50.1 million AMT credit carryover refund, lower operating costs, interest, and cash G&A expenses, offset by lower realized cash gains on commodity hedges.

2016 versus 2015

In 2016, net oil and natural gas sales and adjusted funds flow decreased compared to 2015, due to weak commodity price and lower production volumes as a result of our non-core asset divestments and reduced capital spending. We reported net income of $397.4 million in 2016 compared to a net loss of $1,523.4 million in 2015, primarily as a result of decreases in non-cash impairment charges of $1,051.3 million and in DD&A of $179.2 million recorded on our crude oil and natural gas assets, and non-cash gains of $578.5 million on asset divestments and the prepayment of senior notes.

QUARTERLY FINANCIAL INFORMATION

($ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2017				
Fourth Quarter	$ 271.1	$ 15.3	$ 0.06	$ 0.06
Third Quarter	196.1	$ 16.1	$ 0.07	$ 0.07
Second Quarter	225.7	129.3	0.53	0.52
First Quarter	227.8	76.3	0.32	0.31
Total 2017	$ 920.7	$ 237.0	$ 0.98	$ 0.96
2016				
Fourth Quarter	$ 217.4	$ 840.3	$ 3.49	$ 3.43
Third Quarter	188.3	(100.7)	(0.42)	(0.42)
Second Quarter	174.3	(168.5)	(0.77)	(0.77)
First Quarter	142.7	(173.7)	(0.84)	(0.84)
Total 2016	$ 722.7	$ 397.4	$ 1.75	$ 1.72

Oil and natural gas sales, net of royalties, increased in 2017 compared to 2016 due to an increase in realized commodity prices, offset by a decrease in production due to non-core asset divestments. Net income for 2017 decreased to $237.0 million from $397.4 million in 2016, due to lower gains recorded on asset divestments, along with an increase in deferred tax expense. Net income was higher in the second quarter of 2017 due to a $78.4 million gain recorded on the divestment of certain Canadian assets.

During 2016, the impact of weak commodity prices and lower production with non-core asset divestments, resulted in lower oil and natural gas sales, net of royalties. The lower commodity price environment, combined with non-cash impairment charges contributed to net losses in the first through third quarter of 2016. In the fourth quarter of 2016 a portion of our valuation allowance was removed on our deferred income tax assets resulting in a significant deferred income tax recovery and net income.

ENVIRONMENT

We strive to carry out our activities and operations in compliance with all applicable regulations and best industry practices. Our operations are subject to laws and regulations concerning pollution, protection of the environment and the handling of hazardous materials and waste. We set corporate targets and mandates to improve environmental performance and execute environmental initiatives to become more energy efficient and to reduce, reuse and recycle water and minimize waste.

We have a Safety and Social Responsibility Policy ("S&SR Policy"), which articulates our commitment to health and safety, stakeholder engagement, environmental and regulatory compliance. Our Board of Directors and President & Chief Executive Officer are ultimately accountable for ensuring compliance with the S&SR Policy. The Safety & Social Responsibility Committee of our Board of Directors (the "S&SR Committee") is responsible for overseeing our S&SR performance, ensuring there are adequate systems in place to support ongoing compliance, and to plan and execute the Company's activities in a safe and socially responsible manner.

We have established processes and programs designed to evaluate and minimize health, safety, and environmental risks, and strive for continuous improvement in our S&SR performance. We also actively participate in industry recognized programs that support our sustainability goals.

The S&SR Policy articulates our commitment to protecting the health and safety of all persons and communities involved in, or affected by, our business activities, and articulates our commitment to the environment. It states we endeavor to: (i) proactively manage our impact on the environment and consider innovative improvement opportunities; (ii) work to reduce our environmental impact in the areas in which we operate; (iii) improve our water and land use practices; (iv) limit the waste we generate; (v) prevent and manage environmental releases; (vi) provide transparent disclosure; and (vii) provide resources and training to meet our environmental commitments. Our commitment to building meaningful and transparent relationships, engaging with our stakeholders, and adhering to responsible development of resources and regulatory compliance is also stated.

We intend to continue to improve energy efficiencies and proactively manage our greenhouse gas emissions in compliance with applicable government regulations, including regulations enacted at the provincial, state, and federal levels in which we operate.

There are inherent risks of spills and pipeline leaks at our operating sites and clean-up costs may be significant. However, we have active site inspection, corrosion risk management and asset integrity management programs to help minimize this risk. In addition, we carry environmental insurance to help mitigate the cost of releases should they occur.

Some of our operations use hydraulic fracturing techniques, which involves the injection of pressurized fluids, sand, and small amounts of additives into a well bore. Government and regulatory agencies continue to frame regulations related to this process. We believe we are in compliance with all current government regulations and industry best practices in the U.S. and Canada.

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

Annually, we publish a Corporate Sustainability Report in accordance with the Global Reporting Initiative (GRI) international standard. The report summarizes our environmental, safety, social responsibility and governance performance, and can be found on our website at www.enerplus.com.

Overall, we strive to operate in a socially responsible manner and believe our health, safety and environmental initiatives and performance confirm our ongoing commitment to environmental stewardship and the health and safety of our employees, contractors, and the public in the communities in which we operate.

CRITICAL ACCOUNTING ESTIMATES

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

Oil and Natural Gas Properties and Reserves

Enerplus follows the full cost method of accounting for oil and natural gas properties. The process of estimating reserves is critical in determining several accounting estimates including the Company's depletion, ceiling test, valuation allowance and gain or loss calculations. Estimating reserves requires significant judgments based on available geological, geophysical, engineering and economic data. These estimates may change substantially as data from ongoing development and production activities becomes available, and as economic conditions impacting oil and natural gas prices, operating costs and royalty burdens change. Reserves estimates impact net income through depletion, the determination of asset retirement obligation and the application of impairment tests. Revisions or changes in reserves estimates can have either a positive or a negative impact on net income.

Asset Impairment

Ceiling Test

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

Goodwill

Goodwill, which represents the excess of purchase price over fair value of net assets acquired, is assessed for impairment at least annually at December 31. Goodwill and all other assets and liabilities are allocated to reporting units. To assess impairment, the carrying amount of each reporting unit is determined and compared to the fair value of the reporting unit. If the carrying amount of the reporting unit is higher than its related fair value then goodwill is written down to the reporting unit's implied fair value of goodwill. The fair value used in the impairment test is based on estimates of discounted future cash flows which involve assumptions of natural gas and liquids reserves, including commodity prices, future costs and discount rates.

Income Taxes

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

Asset Retirement Obligation

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

Business Combinations

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

Derivative Financial Instruments

We utilize derivative financial instruments to manage our exposure to market risks relating to commodity prices, foreign currency exchange rates and interest rates. Fair values of derivative contracts fluctuate depending on the underlying estimate of future commodity prices, foreign currency exchange rates, interest rates and counterparty credit risk.

RECENT U.S. GAAP ACCOUNTING AND RELATED PRONOUNCEMENTS

Refer to Note 2(o) in our Financial Statements for a detailed listing of Standards and Interpretations that were issued but not yet effective at December 31, 2017.

RISK FACTORS AND RISK MANAGEMENT

Commodity Price Risk

Our operating results and financial condition are dependent on the prices we receive for our crude oil, natural gas liquids, and natural gas production. These prices have fluctuated widely in response to a variety of factors including global and domestic supply and demand of crude oil, natural gas and natural gas liquids, economic conditions including currency fluctuations, weather conditions, the level of consumer demand, the ability to export oil and liquefied natural gas and natural gas liquids from North America and the supply and price of imported oil and liquefied natural gas, the production and storage levels of North American crude oil, natural gas and natural gas liquids, political stability, transportation facilities, availability of processing, fractionation and refining facilities, the effect of world-wide energy conservation and greenhouse gas reduction measures, the price and availability of alternative fuels and existing and proposed changes to government regulations.

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

We may use financial derivative instruments and other hedging mechanisms to help limit the adverse effects of natural gas, natural gas liquids and crude oil price volatility. However, we do not hedge all of our production and expect there will always be a portion that remains unhedged. Furthermore, we may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, we may forego the benefits that would otherwise be experienced if commodity prices increase. At February 20, 2018, approximately 65% of our 2018 forecasted crude oil production, net of royalties, and 20% of our 2018 forecasted natural gas production, net of royalties, are hedged at price levels disclosed in the "Price Risk Management" section above. For 2019 we have also hedged approximately 61%, of our forecasted 2018 crude oil production, net of royalties. Refer to the "Price Risk Management" section for further details on our price risk management program.

Risk of Increased Capital or Operating Costs

Higher capital or operating costs associated with our operations will directly impact our capital efficiencies and cash flow. Capital costs of completions, specifically the costs of proppant, and operating costs such as electricity, chemicals, supplies, energy services and labour costs, are a few of the costs that are susceptible to material fluctuation. Although we have a portion of our 2018 capital and operating costs protected with existing agreements and contract reopeners, changing regulatory conditions, such as those in the U.S. requiring that certain raw materials be sourced from the U.S., may result in higher than expected supply costs.

Risk of Curtailed or Shut-in Production

Should we be required to curtail or shut-in production as a result of low commodity prices, environmental regulation or third party operational practices, it could result in a reduction to cash flow and production levels, and may result in additional operating and capital costs for the well to achieve prior production levels. In addition, curtailments or shut-ins may cause damage to the reservoir and may prevent us from achieving production and operating levels that were in place prior to the curtailment or shutting-in of the reservoir. With regard to curtailment, although regional pipeline capacity has increased over the past several years, sales gas infrastructure capacity in northeastern Pennsylvania remains constrained relative to the amount of natural gas that can be produced. Combined with the ongoing volatility in natural gas prices, this may result in continued discounted prices and an ongoing risk of price-related production curtailments.

Regulatory Risk and Greenhouse Gas Emissions

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

Government regulations may be changed from time to time in response to economic or political conditions, including the election of new state, provincial or federal leaders. Additionally, our entry into new jurisdictions or adoption of new technology may attract additional regulatory oversight which could result in higher costs or require changes to proposed operations. Canadian and U.S. governments have enhanced their oversight and reporting obligations associated with fracturing procedures and increased their scrutiny of the usage and disposal of chemicals and water used in fracturing procedures. Additionally, various levels of Canadian and U.S. governments are considering or have implemented legislation to reduce emissions of greenhouse gases, including volatile organic compounds ("VOC"), and methane gas emissions.

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

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

Access to Field Services

Our ability to drill, complete and tie-in wells in a timely manner may be impacted by our access to service providers and supplies. Activity levels in each area may limit our access to these resources, restricting our ability to execute our capital plans in a timely manner. In addition, field service costs are influenced by market conditions and therefore can become cost prohibitive.

Although we have entered into service contracts for a portion of field services that will secure some of our drilling and fracturing services through 2018, access to field services and supplies in other areas of our business will continue to be subject to market availability.

Access to Transportation and Processing Capacity

Market access for crude oil, natural gas liquids and natural gas production in Canada and the U.S. is dependent on our ability, and the ability of our buyers as applicable, to obtain transportation capacity on third party pipelines and rail as well as access to processing facilities. As production increases in prolific resource plays such as the North Dakota Bakken and the Marcellus shale gas, it is possible production may exceed the existing capacity of the gathering, pipeline, processing or rail infrastructure. While third party pipelines, processors and independent rail operators generally expand capacity to meet market needs, there can be differences in timing between the growth of production and the growth of capacity. There are occasionally operational reasons for curtailing transportation and processing capacity. Accordingly, there can be periods where transportation and processing capacity is insufficient to accommodate all the production from a given region, causing added expense and/or volume curtailments for all shippers. Our assets are concentrated in specific regions with varying levels of government that could limit or ban the shipping of commodities by truck, pipeline or rail. Special interest groups could also oppose infrastructure development and/or expansion resulting in a delay or even the cancellation of the required infrastructure, further impeding our ability to produce and market our products. Additionally, the transportation of crude oil by rail has been under closer scrutiny by government regulatory agencies in Canada and the U.S. over the past few years. As a result, transporting crude oil by rail may carry a higher cost versus traditional pipeline infrastructure or other means of transporting production. There is a risk that access to rail transport may be constrained, depending upon any changes made to existing rail transport regulations.

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

Oil and Gas Reserves and Resources Risk

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

Each year, independent reserves engineers evaluate the majority of our proved and probable reserves as well as evaluate or audit the resources attributable to a significant portion of our undeveloped land. All reserves information, including our U.S. reserves, has been prepared in accordance with NI 51-101 standards. For U.S. GAAP accounting purposes, our proved reserves are estimated to be technically the same as our proved reserves prepared under NI 51-101 and have been adjusted for the effects of SEC constant prices. Independent reserves evaluations have been conducted on approximately 92% of the total proved plus probable net present value (discounted at 10% and using NI 51-101 standards) of our reserves at December 31, 2017. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 59% of our Canadian reserves and reviewed the internal evaluation completed by Enerplus on the remaining portion. McDaniel also evaluated 100% of the reserves associated with our U.S. tight oil assets. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated 100% of our U.S. Marcellus shale gas assets.

The evaluations of best estimate development pending contingent resources associated with a portion of our Canadian waterflood properties and our Fort Berthold assets were conducted by Enerplus' qualified reserves evaluators and audited by McDaniel. NSAI evaluated our Marcellus shale gas best estimate development pending contingent resources.

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

Production Replacement Risk

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

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

Ability to Divest Properties

Recent regulatory changes in Alberta and Saskatchewan have increased the minimum corporate liability rating required of purchasers of crude oil and natural gas properties. As a result, the potential number of parties able to acquire our non-core assets has been reduced, we may not be able to obtain full value for such assets, or transactions may involve greater risk and complexity.

Anticipated Benefits of Acquisitions or Divestments

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

When acquiring assets, we are subject to inherent risks associated with predicting the future performance of those assets. We may make certain estimates and assumptions respecting the characteristics of the assets we acquire, that may not be realized over time. As such, assets acquired may not possess the value we attribute to them, which could adversely impact our future cash flows. To the extent that we make acquisitions with higher growth potential, the higher risks often associated may result in increased chances that actual results may vary from our initial estimates. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods, approaches, and assumptions than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments.

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

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

Access to Capital Markets

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

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

Risk of Public Opposition and Activism

The oil and natural gas industry elicits concerns over climate change, as well as general public opposition to the industry. As a result, industry participants such as Enerplus may be subject to increased public activism, as well as extensive environmental regulation. Activist activity may result in increased costs due to delays or damage.

The expansion of our business activities, both geographically and with a focus on exploration, may draw increased attention from shareholder activists who oppose our strategy, which could have an adverse effect on market value. Our ongoing participation in the Canadian and U.S. capital markets may expose us to greater risk of class action lawsuits related to securities law, title, contractual and environmental matters.

Health, Safety and Environmental Risk

Health, safety and environmental risks impact our workforce and operating costs and result in the enhancement of our business practices and standards. There may be risks associated with hydraulic fracturing or produced water disposal including the risk of induced seismicity with the injection of fluid into any reservoir. We expect regulatory frameworks will be amended or continue to emerge in this regard. Although Enerplus proactively mitigates perceived risks involved in the hydraulic fracturing process, increased capital and operating costs may be incurred if regulations in Canada or the U.S. impose more stringent compliance requirements surrounding hydraulic fracturing. The impact of such changes on our business could increase our cost of compliance and the risk of litigation and environmental liability.

We have an S&SR department that develops standards and systems to manage health, safety and environmental risks, and regulatory compliance. The S&SR Committee of our Board of Directors is responsible for overseeing the organization's health, safety and environmental performance and ensuring there are adequate systems in place to support ongoing compliance, and to plan and execute activities in a safe and socially responsible manner. We have insurance to cover a portion of our property losses, liability and business interruption. At present, we believe we are, and expect to continue to be, in compliance with all material applicable environmental laws and regulations and have included appropriate amounts in our capital expenditure budget to continue to meet our ongoing environmental obligations.

Changes in Income Tax and Other Laws

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

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

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

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

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

Goodwill impairment testing is performed on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. We perform a qualitative assessment by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to net income.

Commodity prices improved in 2017 and no impairment was recorded on our crude oil and natural gas assets, compared to a non-cash impairment of $301.2 million in 2016. With the improvement in commodity prices, we removed our remaining non-capital valuation allowance on our deferred tax asset in 2017 due to higher projected future taxable income in Canada and the U.S. We recorded no goodwill impairments in 2017 and 2016. There is a risk of impairment on our oil and gas properties, deferred tax asset and goodwill if commodity prices weaken, costs increase, or if there is a downward revision to reserves. Please refer to the "Impairments" and "Income Taxes" sections of the MD&A and Notes 5 and 12 of the Financial Statements for further details.

Foreign Currency Exposure

We have exposure to fluctuations in foreign currency as most of our senior notes are denominated in U.S. dollars. Our U.S. operations are directly exposed to fluctuations in the U.S. dollar when translated to our Canadian dollar denominated financial statements. We also have indirect exposure to fluctuations in foreign currency as our crude oil sales and a portion of our natural gas sales are based on U.S. dollar indices. Our oil and gas revenues are positively impacted when the Canadian dollar weakens relative to the U.S. dollar. However, our U.S. capital spending, transportation and operating costs, interest expense and debt repayments are negatively impacted with a weak Canadian dollar.

Currently, we do not have any foreign exchange contracts in place to hedge our foreign exchange exposure. However, we continue to monitor fluctuations in foreign exchange and the impact on our operations.

Title Defects or Litigation

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

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

Cyber Security Risks

We are subject to a variety of information technology and system risks as part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach and destruction or interruption of our information technology systems by third parties or insiders. Although we have security measures and controls in place that are designed to mitigate these risks, a breach of our security and/or a loss of information could occur and result in a loss of material and confidential information, reputation damage, a breach in privacy laws and disruption to business activities. The significance of any such event is difficult to quantify, but may be material in certain circumstances and could have a material effect on our business, financial condition and results of operations.

Counterparty and Joint Venture Credit Exposure

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

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

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

Debt covenants may be exceeded with no ability to negotiate covenant relief

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

Our most restrictive debt covenant is a maximum senior debt to adjusted EBITDA ratio of 3.5x for a period of up to six months, after which it drops to 3.0x. At December 31, 2017, our senior debt to adjusted EBITDA ratio was 1.2x. We routinely review our compliance with covenants based on actual and forecasted results, and have the ability to adjust our capital spending levels and dividends or pursue asset divestments and equity issuances to comply with our covenants.

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

Interest Rate Exposure

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

Currently, we do not have any floating interest rate debt. At December 31, 2017, we were undrawn on our $800 million bank credit facility, and our debt consisted of fixed interest rate senior notes.

ADJUSTED FUNDS FLOW SENSITIVITY

The sensitivities below reflect all commodity contracts listed in Note 14 to the Financial Statements and are based on 2018 guidance price levels. To the extent crude oil and natural gas prices change significantly from current levels, the sensitivities will no longer be relevant.

Sensitivity Table	Estimated Effect on 2018 Adjusted Funds Flow per Share(1)
Change of US$0.50 per Mcf in the price of NYMEX natural gas(2)	$ 0.19
Change of US$5.00 per barrel in the price of WTI crude oil(2)	$ 0.19
Change of 1,000 BOE/day in production	$ 0.03
Change of $0.01 in the US/CDN exchange rate	$ 0.02
Change of 1% in interest rate(3)	$ nil

(1) Assumes 242.1 million weighted average shares outstanding.
(2) Includes the impact of commodity derivative instruments.
(3) There is no impact to adjusted funds flow for an increase in interest rates, as Enerplus is currently undrawn on its floating interest rate bank credit facility and all outstanding senior notes are based on fixed interest rates.

2018 GUIDANCE

A summary of our previously released 2018 guidance is below.

Summary of 2018 Expectations	Target
Capital spending	$535 - $585 million
Average annual production	86,000 – 91,000 BOE/day
Average annual crude oil and natural gas liquids production	46,000 – 50,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	25%
Operating expenses	$7.00/BOE
Transportation costs	$3.60/BOE
Cash G&A expenses	$1.65/BOE

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

(1) Excluding transportation costs.

NON-GAAP MEASURES

The Company utilizes the following terms for measurement within the MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and therefore may not be comparable with the calculation of similar measures by other entities:

"Netback" is used by Enerplus and is useful to investors and securities analysts in evaluating operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

Calculation of Netback	Year ended December 31,		
($ millions)	2017	2016	2015
Oil and natural gas sales, net of royalties	$ 920.7	$ 722.7	$ 884.4
Less:			
Production taxes	(54.3)	(37.4)	(50.9)
Cash operating expenses(1)	(197.7)	(249.0)	(340.1)
Transportation costs	(111.3)	(107.1)	(114.7)
Netback before hedging	$ 557.4	$ 329.2	$ 378.7
Cash gains/(losses) on derivative instruments	8.6	80.3	287.7
Netback after hedging	$ 566.0	$ 409.5	$ 666.4

(1) Operating costs adjusted to exclude non-cash gains on fixed price electricity swaps of $0.6 million in 2017, gains of $1.1 million in 2016 and losses of $0.4 million in 2015.

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

Reconciliation of Cash Flow from Operating Activities to Adjusted Funds Flow	**Year ended December 31,**		
($ millions)	**2017**	**2016**	**2015**
Cash flow from operating activities	$ 476.2	$ 312.3	$ 465.3
Asset retirement obligation expenditures	12.9	8.4	14.9
Changes in non-cash operating working capital	35.0	(15.1)	12.9
Adjusted funds flow	$ 524.1	$ 305.6	$ 493.1

"Net debt to adjusted funds flow ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The net debt to adjusted funds flow ratio is calculated as total debt net of cash, including restricted cash, divided by a trailing 12 months of adjusted funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization, impairment and other non-cash charges ("adjusted EBITDA") and is not a debt covenant.

"Adjusted payout ratio" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. We calculate our adjusted payout ratio as cash dividends plus capital and office expenditures divided by adjusted funds flow.

Calculation of Adjusted Payout Ratio	**Year ended December 31,**		
($ millions)	**2017**	**2016**	**2015**
Cash dividends	$ 29.0	$ 35.4	$ 132.0
Capital and office expenditures	460.7	210.6	497.9
Sub-total	$ 489.7	$ 246.0	$ 629.9
Adjusted funds flow	$ 524.1	$ 305.6	$ 493.1
Adjusted payout ratio (%)	93%	80%	128%

"Adjusted EBITDA" is used by Enerplus and its lenders to determine compliance with financial covenants under its bank credit facility and outstanding senior notes.

Reconciliation of Net Income to Adjusted EBITDA(1)	
($ millions)	**December 31, 2017**
Net income/(loss)	$ 237.0
Add:	
Interest	38.7
Current and deferred tax expense/(recovery)	82.0
DD&A and asset impairment	250.8
Other non-cash charges(2)	(26.2)
Sub-total	$ 582.3
Adjustment for material acquisitions and divestments(3)	(12.3)
Adjusted EBITDA	$ 570.0

(1) Adjusted EBITDA is calculated based on the trailing four quarters.
(2) Includes the change in fair value of commodity derivatives, fixed price electricity swaps and equity swaps, non-cash SBC, and unrealized foreign exchange gains/losses.
(3) EBITDA is adjusted for material acquisitions or divestments during the period with net proceeds greater than $50 million as if that acquisition or divestment had been made at the beginning of the period.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "debt net of cash", "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "maximum debt to consolidated present value of total proved reserves" and "adjusted EBITDA to interest" and are used to determine the Company's compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of such terms is described under the "Liquidity and Capital Resources" section of this MD&A.

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal controls over financial reporting as defined in Rule 13a – 15 under the U.S. Securities Exchange Act of 1934 and as defined in Canada under National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at December 31, 2017, our disclosure controls and procedures and internal control over financial reporting were effective. There were no changes in our internal control over financial reporting during the period beginning on January 1, 2017 and ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ADDITIONAL INFORMATION

Additional information relating to Enerplus, including our current Annual Information Form, is available under our profile on the SEDAR website at www.sedar.com, on the EDGAR website at www.sec.gov and at www.enerplus.com.

This MD&A contains certain forward-looking information and statements ("forward-looking information") within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "ongoing", "may", "will", "project", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this MD&A contains forward-looking information pertaining to the following: 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 and the timing of related production; oil and natural gas prices and differentials and our commodity risk management program 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 G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2018 and impact thereof on our production levels and land holdings; potential future asset and goodwill impairments, as well as relevant factors that may affect such impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes; future debt and working capital levels and net debt to adjusted funds flow ratio and adjusted payout ratio, financial capacity, liquidity and capital resources to fund capital spending and working capital requirements; expectations regarding our ability to comply with debt covenants under our bank credit facility and outstanding senior notes and to negotiate relief if required; our future acquisitions and dispositions, expecting timing thereof and use of proceeds therefrom; and the amount of future cash dividends that we may pay to our shareholders.

The forward-looking information contained in this MD&A reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; 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 MD&A 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. Enerplus believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: continued low commodity prices environment or future 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 identified in our AIF and Form 40-F as at December 31, 2017).*

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

Management's Report on Internal Control over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2017, our internal control over financial reporting is effective.

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

The effectiveness of the Company's internal control over financial reporting as of December 31, 2017, has been audited by KPMG LLP, the Independent Registered Public Accounting Firm, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2017.

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 23, 2018

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of Enerplus Corporation

Opinion on Internal Control Over Financial Reporting

We have audited Enerplus Corporation's (the "Entity") internal control over financial reporting as of December 31, 2017, based on the criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the Entity maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Report on the Consolidated Financial Statements

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Entity, which comprise the consolidated balance sheet as at December 31, 2017, the consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows for the year then ended, and the related notes (collectively referred to as the consolidated financial statements) and our report dated February 23, 2018 expressed an unmodified (unqualified) opinion on those consolidated financial statements.

Basis for Opinion

The Entity's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Entity's internal control over financial reporting based on our audit.

We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Entity in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB and in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada.

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

/s/ KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 23, 2018

Management's Responsibility for Financial Statements

In management's opinion, the accompanying consolidated financial statements of Enerplus Corporation have been prepared within reasonable limits of materiality and in accordance with accounting principles generally accepted in the United States of America. Since a precise determination of many assets and liabilities is dependent on future events, the preparation of financial statements necessarily involves the use of estimates and approximations. These have been made using careful judgment and with all information available up to February 22, 2018. Management is responsible for all information in the annual report and for the consistency, therewith, of all other financial and operating data presented in this report.

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

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

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

/s/ Ian C. Dundas

President and
Chief Executive Officer

/s/ Jodine J. Jenson Labrie

Senior Vice President and
Chief Financial Officer

Calgary, Alberta
February 23, 2018

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of Enerplus Corporation (the "Entity"), which comprise the consolidated balance sheet as at December 31, 2017, the consolidated statements of income (loss) and comprehensive income (loss), changes in shareholders' equity and cash flows for the year then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information (collectively referred to as the "consolidated financial statements").

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Entity as at December 31, 2017, and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with accounting principles generally accepted in the United States of America.

Report on Internal Control Over Financial Reporting

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Entity's internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 23, 2018 expressed an unqualified (unmodified) opinion on the effectiveness of the Entity's internal control over financial reporting.

Basis for Opinion

A - Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

B - Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards and the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement, whether due to error or fraud. Those standards also require that we comply with ethical requirements, including independence. We are required to be independent with respect to the Entity in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. We are a public accounting firm registered with the PCAOB.

An audit includes performing procedures to assess the risks of material misstatements of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included obtaining and examining, on a test basis, audit evidence regarding the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances.

An audit also includes evaluating the appropriateness of accounting policies and principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a reasonable basis for our audit opinion.

Comparative Information

The consolidated financial statements of the Entity as at December 31, 2016 and for the years ended December 31, 2016 and 2015, excluding the impact of adoption of ASU 2016-18 as described in Note 2(o) to the consolidated financial statements, were audited by another auditor who expressed an unqualified (unmodified) opinion on those financial statements on February 24, 2017.

As part of our audit of the consolidated financial statements as at and for the year ended December 31, 2017, we audited the adoption of ASU 2016-18 as described in Note 2(o) to the consolidated financial statements that was applied to amend the comparative information presented for the year ended December 31, 2016. In our opinion, the adoption of ASU 2016-18 has been properly applied.

We were not engaged to audit, review, or apply any procedures to the consolidated financial statements of the Entity as at December 31, 2016 and for the years ended December 31, 2016 and 2015, other than with respect to the amendment described in Note 2(o) to the consolidated financial statements. Accordingly, we do not express an opinion or any other form of assurance on those financial statements taken as a whole.

/s/ KPMG LLP

Chartered Professional Accountants

This is our first year of service as the Entity's auditor.
Calgary, Canada
February 23, 2018

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors of Enerplus Corporation

We have audited, before the effects of the adjustments to retrospectively apply ASU 2016-18 adopted in 2017 as discussed in Note 2(o)(i) to the consolidated financial statements, the accompanying consolidated financial statements of Enerplus Corporation and subsidiaries (the "Company"), which comprise the consolidated balance sheet as at December 31, 2016 and the consolidated statements of income/(loss) and comprehensive income/(loss), consolidated statements of changes in shareholders' equity, and consolidated statements of cash flows for each of the years in the two-year period ended December 31, 2016, and the notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, such consolidated financial statements, before the effects of the adjustments to retrospectively apply ASU 2016-18 adopted in 2017 as discussed in Note 2(o)(i) to the consolidated financial statements, present fairly, in all material respects, the financial position of Enerplus Corporation and subsidiaries as at December 31, 2016 and their financial performance and their cash flows for each of the years in the two-year period ended December 31, 2016 in accordance with accounting principles generally accepted in the United States of America.

Other Matter

We were not engaged to audit, review, or apply any procedures to the adjustments to retrospectively adopt ASU 2016-18 as discussed in Note 2(o)(i) to the consolidated financial statements and, accordingly, we do not express an opinion or any other form of assurance about whether such retrospective adjustments are appropriate and have been properly applied. Those retrospective adjustments were audited by other auditors.

/s/ Deloitte LLP

Chartered Professional Accountants
February 24, 2017

Consolidated Balance Sheets

(CDN$ thousands)	Note	December 31, 2017	December 31, 2016
Assets			
Current assets			
Cash and cash equivalents		$ 346,548	$ 1,257
Restricted cash	2(f)	—	392,048
Accounts receivable	3	130,576	115,368
Derivative financial assets	14(b)	3,852	—
Other current assets		5,902	6,721
		486,878	515,394
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	889,967	726,452
Other capital assets, net	4	10,064	11,978
Property, plant and equipment		900,031	738,430
Goodwill	5(b)	638,878	651,663
Deferred income tax asset	12	569,937	733,363
Income tax receivable	12	50,108	—
Total Assets		$ 2,645,832	$ 2,638,850
Liabilities			
Current liabilities			
Accounts payable	6	$ 213,978	$ 184,534
Dividends payable		2,421	2,405
Current portion of long-term debt	7	27,656	29,539
Derivative financial liabilities	14(b)	28,642	28,615
		272,697	245,093
Derivative financial liabilities	14(b)	9,907	12,266
Long-term debt	7	644,723	739,286
Asset retirement obligation	8	117,736	181,700
		772,366	933,252
Total Liabilities		1,045,063	1,178,345
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value			
Issued and outstanding: December 31, 2017 - 242 million shares			
December 31, 2016 - 240 million shares	13(a)	3,386,946	3,365,962
Paid-in capital		75,375	73,783
Accumulated deficit		(2,124,676)	(2,332,641)
Accumulated other comprehensive income		263,124	353,401
		1,600,769	1,460,505
Total Liabilities & Shareholders' Equity		$ 2,645,832	$ 2,638,850

Commitments and Contingencies 15

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

Approved on behalf of the Board of Directors:

/s/ Elliott Pew
Director

/s/ Robert B. Hodgins
Director

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

For the year ended December 31 (CDN$ thousands)	Note	2017	2016	2015
Revenues				
Oil and natural gas sales, net of royalties	9	$ 920,693	$ 722,732	$ 884,392
Commodity derivative instruments gain/(loss)	14(b)	14,310	(29,397)	142,724
		935,003	693,335	1,027,116
Expenses				
Operating		197,101	247,917	340,483
Transportation		111,265	107,147	114,691
Production taxes		54,318	37,417	50,899
General and administrative	10	74,301	86,319	103,870
Depletion, depreciation and accretion		250,774	328,964	508,179
Asset impairment	5	—	301,171	1,352,428
Interest		38,714	45,443	66,456
Foreign exchange (gain)/loss	11	(30,150)	(40,526)	173,933
Gain on divestment of assets	4	(78,400)	(559,235)	—
Gain on prepayment of senior notes	7	—	(19,270)	—
Other expense /(income)		(1,906)	(2,230)	7,055
		616,017	533,117	2,717,994
Income/(Loss) Before Taxes		318,986	160,218	(1,690,878)
Current income tax expense/(recovery)	12	(47,957)	(2,351)	(16,887)
Deferred income tax expense/(recovery)	12	129,945	(234,847)	(150,588)
Net Income/(Loss)		$ 236,998	$ 397,416	$ (1,523,403)
Other Comprehensive Income/(Loss)				
Change in cumulative translation adjustment		(90,277)	(49,271)	307,194
Other Comprehensive Income/(Loss)		(90,277)	(49,271)	307,194
Total Comprehensive Income/(Loss)		$ 146,721	$ 348,145	$ (1,216,209)
Net Income/(Loss) per Share				
Basic	13(c)	$ 0.98	$ 1.75	$ (7.39)
Diluted	13(c)	$ 0.96	$ 1.72	$ (7.39)

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

Consolidated Statements of Changes in Shareholders' Equity

For the year ended December 31 (CDN$ thousands)	**2017**	**2016**	**2015**
Share Capital			
Balance, beginning of year	$ 3,365,962	$ 3,133,524	$ 3,120,002
Public offering (net of issue costs)	—	223,031	—
Share-based compensation – settled	20,984	9,407	10,050
Stock Option Plan – cash	—	—	3,205
Stock Option Plan – exercised	—	—	267
Balance, end of year	$ 3,386,946	$ 3,365,962	$ 3,133,524
Paid-in Capital			
Balance, beginning of year	$ 73,783	$ 56,176	$ 46,906
Share-based compensation – settled	(20,984)	(9,407)	(10,050)
Share-based compensation – non-cash	22,576	27,014	19,587
Stock Option Plan – exercised	—	—	(267)
Balance, end of year	$ 75,375	$ 73,783	$ 56,176
Accumulated Deficit			
Balance, beginning of year	$ (2,332,641)	$ (2,694,618)	$ (1,039,260)
Net income/(loss)	236,998	397,416	(1,523,403)
Dividends declared	(29,033)	(35,439)	(131,955)
Balance, end of year	$ (2,124,676)	$ (2,332,641)	$ (2,694,618)
Accumulated Other Comprehensive Income			
Balance, beginning of year	$ 353,401	$ 402,672	$ 95,478
Change in cumulative translation adjustment	(90,277)	(49,271)	307,194
Balance, end of year	$ 263,124	$ 353,401	$ 402,672
Total Shareholders' Equity	$ 1,600,769	$ 1,460,505	$ 897,754

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

Consolidated Statements of Cash Flows

For the year ended December 31 (CDN$ thousands)	Note	2017	2016	2015
Operating Activities				
Net income/(loss)		$ 236,998	$ 397,416	$ (1,523,403)
Non-cash items add/(deduct):				
Depletion, depreciation and accretion		250,774	328,964	508,179
Asset impairment	5(a)	—	301,171	1,352,428
Changes in fair value of derivative instruments	14(b)	(6,184)	105,026	169,336
Deferred income tax expense/(recovery)	12	129,945	(234,847)	(150,588)
Foreign exchange (gain)/loss on debt and working capital	11	(42,623)	(40,634)	160,791
Share-based compensation	13(b)	22,576	27,014	19,587
Translation of U.S. dollar cash held in Canada	11	10,978	—	—
Gain on the divestment of assets	4	(78,400)	(559,235)	—
Gain on prepayment of senior notes	7	—	(19,270)	—
Derivative settlement of foreign exchange swaps	14(c)	—	—	(43,229)
Asset retirement obligation expenditures	8	(12,907)	(8,390)	(14,935)
Changes in non-cash operating working capital	17(a)	(35,032)	15,075	(12,830)
Cash flow from operating activities		476,125	312,290	465,336
Financing Activities				
Proceeds from the issuance of shares (net of issue costs)	13(a)	—	220,410	3,205
Dividends	13(a),17(b)	(29,017)	(39,230)	(144,275)
Bank credit facility	7	(23,272)	(55,999)	6,626
Senior notes	7	(29,084)	(335,400)	(103,198)
Derivative settlement on senior notes	14(c)	—	—	43,229
Cash flow from/(used in) financing activities		(81,373)	(210,219)	(194,413)
Investing Activities				
Capital and office expenditures	17(b)	(459,152)	(260,083)	(545,461)
Property and land acquisitions	4	(13,276)	(126,126)	(9,552)
Property divestments	4	56,196	670,364	286,614
Cash flow from/(used in) investing activities		(416,232)	284,155	(268,399)
Effect of exchange rate changes on cash and cash equivalents		(25,277)	(419)	2,938
Change in cash and cash equivalents		(46,757)	385,807	5,462
Cash and cash equivalents, beginning of year		393,305	7,498	2,036
Cash and cash equivalents, end of year		$ 346,548	$ 393,305	$ 7,498

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

Notes to Consolidated Financial Statements

1) REPORTING ENTITY

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

2) SIGNIFICANT ACCOUNTING POLICIES

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

a) Basis of Preparation

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

i. Reporting Currency

These Consolidated Financial Statements are presented in Canadian dollars, which is Enerplus' reporting currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

ii. Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. Actual results could differ from these estimates, and changes in estimates are recorded when known. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows, depreciation, depletion and accretion ("DD&A"), impairment, asset retirement obligations, income taxes, income tax asset values, impairment assessments of goodwill and the fair value of derivative instruments. Enerplus uses the most current information available and exercises judgment in making these estimates and assumptions. In the opinion of management, these Consolidated Financial Statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies.

iii. Basis of Consolidation

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

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

b) Revenue

Revenue associated with the sale of oil and natural gas is recognized when title passes from the Company to its customers if collectability is reasonably certain and the sales price is determinable. Revenue is measured at the fair value of the consideration received or receivable based on price, volumes delivered and contractual delivery points, and presented net of sales and other similar taxes.

c) Transportation

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

Under the other arrangement, Enerplus sells crude oil or natural gas at a specific delivery point, pays transportation to a third party and receives proceeds from the purchaser with no transportation deduction. In this case, transportation costs are recorded as transportation expense on the Consolidated Statements of Income/(Loss). Due to these two distinct selling arrangements, Enerplus' computed realized prices, before the impact of derivative instruments, include revenues which are reported under two separate bases.

d) Oil and Natural Gas Properties

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

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

Under full cost accounting, a ceiling test is performed on a cost centre basis. Enerplus limits capitalized costs of proved and unproved oil and natural gas properties, net of accumulated depletion and deferred income tax liabilities, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties ("the ceiling"). The estimated future net cash flows are calculated using the simple average of the preceding twelve months' first-day-of-the-month commodity prices. If such capitalized costs exceed the ceiling, a write-down equal to that excess is recorded as a non-cash charge to net income. A write-down is not reversed in future periods even if higher oil and natural gas prices subsequently increase the ceiling.

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

e) Other Capital Assets

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

f) Cash and Cash Equivalents and Restricted Cash

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

Restricted cash on the Consolidated Balance Sheets as of December 31, 2016 consists of proceeds from the sale of our non-operated North Dakota properties. The funds were deposited with a qualified intermediary and restricted for application towards future acquisitions to facilitate a potential like-kind exchange transaction for U.S. federal income tax purposes. The funds were withdrawn from escrow on June 29, 2017.

Restricted cash is included in cash and cash equivalents in the Consolidated Statement of Cash Flows.

g) Goodwill

Enerplus recognizes goodwill relating to business acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities acquired. The portion of goodwill that relates to U.S. operations fluctuates due to changes in foreign exchange rates. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

The change in goodwill in 2017 and 2016 related to the impact of foreign exchange movements on U.S. dollar denominated goodwill balances.

Impairment testing is performed on an annual basis or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus performs a qualitative assessment by evaluating potential indicators of impairment, and if it is more likely than not that the fair value of the reporting unit is less than its carrying value, quantitative impairment tests are performed. If the carrying value of the reporting unit exceeds its fair value, goodwill is written down to its implied fair value with an offsetting charge to earnings in the Consolidated Statements of Income/(Loss). For the purposes of goodwill impairment testing, Enerplus has two reporting units.

h) Asset Retirement Obligations

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

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

i) Income Tax

Enerplus uses the liability method of accounting for income taxes. Deferred income tax assets and liabilities are recorded on the temporary differences between the accounting and income tax basis of assets and liabilities, using the enacted tax rates expected to apply when the temporary differences are expected to reverse. Deferred tax assets are reviewed each period and a valuation allowance is provided if, after considering available evidence, it is more likely than not that a deferred tax asset will not be realized. Enerplus considers both positive and negative evidence including historic and expected future taxable income, reversing existing temporary differences and tax basis carry forward periods in making this assessment. A valuation allowance is removed in any period where available evidence indicates all or a portion of the valuation allowance is no longer required. The financial statement effect of an uncertain tax position is recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by a taxation authority. Penalties and interest related to income tax are recognized in income tax expense.

j) Financial Instruments

i. Fair Value Measurements

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

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

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

ii. Non-derivative financial instruments

The carrying amount of cash, restricted cash, accounts receivable, income tax receivable, accounts payable, dividends payable and bank credit facilities reported on the Consolidated Balance Sheets approximates fair value. The fair value of the senior notes are considered a level 2 fair value measurement. The fair value of debt has been disclosed in Note 14.

iii. Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Enerplus has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all financial derivative contracts are classified as held-for-trading and are recorded at fair value based on a Level 2 designation, with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date. Enerplus' accounting policy is to not offset the fair values of its financial derivative assets and liabilities.

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

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

k) Foreign Currency

i. Foreign currency transactions

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

ii. Foreign operations

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

l) Share-Based Compensation

Enerplus' share-based compensation plans include its equity-settled Restricted Share Unit ("RSU") and Performance Share Unit ("PSU") plans. The Company is authorized to issue up to 5% of outstanding common shares from treasury in relation to these plans. Enerplus' Stock Option Plan was suspended in 2014 and is now closed. Enerplus also has certain cash-settled plans, including its Deferred Share Unit ("DSU") plans and previous cash-settled RSU and PSU plans. The final cash-settled PSU and RSU grants were paid in 2015 and 2016, respectively.

i. RSU, PSU, and DSU plans

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

Under Enerplus' PSU plan, executives and management receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. The value upon vesting is based on value of the underlying shares plus notional accrued dividends along with a multiplier that ranges from 0 to 2 depending on Enerplus' performance compared to the TSX oil and gas index over the vesting period.

Under Enerplus' DSU plan, directors receive compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded is based on the annual retainer value and they vest upon the director leaving the Board. The value upon vesting is based on the value of the underlying notional shares plus notional accrued dividends over the vesting period. All DSU grants are settled in cash.

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

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

ii. Stock options

Enerplus' Stock Option Plan was suspended in 2014 and is now closed. All options outstanding under the plan are fully vested and the expense has been fully recognized. Under the plan, employees were granted options to purchase common shares of the Company at an exercise price equal to the market value of the common shares on the date the options are granted. Options granted were exercisable in thirds over the three year vesting schedule and expire seven years after the date the options are granted. Enerplus used the Black-Scholes option pricing model to calculate the grant date fair value of stock options granted under the Company's Stock Option Plan. This amount was charged to earnings as share-based compensation over the vesting period of the options, with a corresponding increase in paid-in capital. When options are exercised, the proceeds, together with the amount recorded in paid-in capital, are recorded to share capital.

m) Net Income Per Share

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

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

n) Contingencies

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

o) Accounting Changes and Recent Pronouncements Issued

i. Recently adopted accounting standards

Effective in 2017, Enerplus adopted the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"):

- ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash*
- ASU 2016-09, *Compensation – Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting*

The adoption of ASU 2016-09 did not have a material impact on Enerplus' Consolidated Financial Statements. As a result of the adoption of ASU 2016-18, restricted cash of $392.0 million at December 31, 2016 has been included in cash and cash equivalents on the Consolidated Statements of Cash Flows. Prior to adoption, changes in restricted cash were included in investing activities. Enerplus' 2016 Consolidated Statement of Cash Flows was restated as required to reflect this change in presentation.

ii. Future accounting changes

In future accounting periods, the Company will adopt the following Accounting Standards Updates ("ASU") issued by the Financial Accounting Standards Board ("FASB"):

In May 2014, the FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606),* which requires entities to recognize revenue on the transfer of promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. The new standard also will require expanded disclosures regarding the nature, amount, timing and certainty of revenue and cash flows from contracts with customers. The FASB further issued several ASUs in 2016 which provide clarification on implementation of the amended standard, technical corrections, improvements and practical expedients that can be applied under certain circumstances. The guidance in Topic 606, as amended, will be effective for annual periods beginning on or after December 15, 2017, and will be adopted by Enerplus on January 1, 2018 using the modified retrospective method. Enerplus has completed its review of sales contracts with customers and has not identified any material impact to the Consolidated Financial Statements other than enhanced disclosures. The Company continues to address any process changes necessary to compile the information to meet the additional note disclosure requirements of the new standard, including the review of new sales contracts entered into after the date of adoption.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842).* The ASU introduced a lessee accounting model that requires lessees to recognize a right-of-use asset and related lease liability on the balance sheet for all leases, including operating leases. The standard does not apply to oil and gas exploration rights, intangible assets or inventory. The new standard also expands disclosures related to the amount, timing and uncertainty of cash flows arising from leases. The standard will be applied using a modified retrospective approach and provides for certain practical expedients at the date of adoption. The ASU is effective January 1, 2019. Enerplus does not expect to early adopt the standard. The Company is currently reviewing existing contracts to determine the impact to the Consolidated Financial Statements of adopting the new standard. The Company is also addressing system and process changes necessary to compile the information to meet the recognition and disclosure requirements of the new standard.

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses (Topic 326)*. The ASU significantly changes how entities measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020, and will be applied using a modified retrospective approach. Enerplus does not expect to early adopt the standard and continues to assess the impact to the Consolidated Financial Statements.

In January 2017, the FASB issued ASU 2017-04, *Intangibles – Goodwill and Other: Simplifying the Test for Goodwill Impairment (Topic 350)*. This standard eliminates Step 2 of the goodwill impairment test, and requires a goodwill impairment charge for the amount that the carrying amount of the reporting unit exceeds the reporting unit's fair value. The updated guidance is effective January 1, 2020, and will be applied prospectively. Enerplus does not expect to early adopt the standard. The amended standard may affect goodwill impairment tests past the adoption date, the impact of which is not known.

In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815),* making more hedging strategies eligible for hedge accounting. The new guidance is effective January 1, 2019, and will be applied prospectively. Hedge accounting continues to be an elective accounting policy choice. Enerplus does not currently apply hedge accounting. Enerplus is currently assessing the impact ASU 2017-12 would have on the Consolidated Financial Statements should it elect to apply hedge accounting.

3) ACCOUNTS RECEIVABLE

($ thousands)	**December 31, 2017**	**December 31, 2016**
Accrued revenue	$ 102,051	$ 83,774
Accounts receivable - trade	30,787	33,305
Current income tax receivable	1,190	1,564
Allowance for doubtful accounts	(3,452)	(3,275)
Total accounts receivable, net of allowance for doubtful accounts	$ 130,576	$ 115,368

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

As at December 31, 2017 ($ thousands)	**Cost**	**Accumulated Depletion, Depreciation, and Impairment**	**Net Book Value**
Oil and natural gas properties	$ 13,622,266	$ (12,732,299)	$ 889,967
Other capital assets	107,582	(97,518)	10,064
Total PP&E	$ 13,729,848	$ (12,829,817)	$ 900,031

As at December 31, 2016 ($ thousands)		Cost		Accumulated Depletion, Depreciation, and Impairment		Net Book Value
Oil and natural gas properties	$	13,567,390	$	(12,840,938)	$	726,452
Other capital assets		106,070		(94,092)		11,978
Total PP&E	$	13,673,460	$	(12,935,030)	$	738,430

Acquisitions:

For the years ended December 31, 2017 and 2016, Enerplus acquired property and land totaling $13.3 million, and $126.1 million, respectively. For the year ended December 31, 2016, acquisitions included the purchase of assets in Ante Creek in NW Alberta for $110.3 million.

Divestments:

For the years ended December 31, 2017 and 2016, Enerplus disposed of properties for proceeds of $56.2 million and $670.4 million, respectively. Certain asset divestments may result in gains if the divestments cause a significant alteration in the relationship between the cost centre's capitalized costs and proved reserves. During 2017 and 2016, Enerplus recognized gains on asset divestments of $78.4 million and $559.2 million, respectively.

5) IMPAIRMENT

a) Impairment of PP&E

($ thousands)		2017		2016		2015
Oil and natural gas properties:						
Canada cost centre	$	—	$	89,359	$	286,700
U.S. cost centre		—		211,812		1,065,728
Total impairment expense	$	—	$	301,171	$	1,352,428

There was no impairment recorded for the year ended December 31, 2017. The impairments for the years ended December 31, 2016 and 2015 were due to lower 12-month average trailing crude oil and natural gas prices.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling test as at December 31, 2017, 2016 and 2015:

Period		WTI Crude Oil US$/bbl	Exchange Rate US$/CDN		Edm Light Crude CDN$/bbl		U.S. Henry Hub Gas US$/Mcf		AECO Natural Gas Spot CDN$/Mcf
2017	$	51.34	1.30	$	63.57	$	2.98	$	2.32
2016		42.75	1.32	$	52.26	$	2.49	$	2.17
2015		50.28	1.27		59.38		2.58		2.69

b) Goodwill Impairment

Goodwill impairment testing is performed annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. Enerplus' annual goodwill impairment assessment as at December 31, 2017 and December 31, 2016 indicated no impairment.

There were no additions or impairments to goodwill for the year ended December 31, 2017 or the comparative years.

6) ACCOUNTS PAYABLE

($ thousands)		December 31, 2017		December 31, 2016
Accrued payables	$	96,743	$	104,816
Accounts payable - trade		117,235		79,718
Total accounts payable	$	213,978	$	184,534

7) DEBT

($ thousands)	December 31, 2017	December 31, 2016
Current:		
Senior notes	$ 27,656	$ 29,539
	27,656	29,539
Long-term:		
Bank credit facility	$ —	$ 23,226
Senior notes	644,723	716,060
	644,723	739,286
Total debt	$ 672,379	$ 768,825

Bank Credit Facility

Enerplus has a senior unsecured, covenant-based, $800 million bank credit facility that matures on October 31, 2020. Drawn fees range between 150 and 315 basis points over bankers' acceptance rates. Standby fees on the undrawn portion of the facility are based on 20% of the drawn pricing. The Company has the ability to request an extension of the facility or repay the entire balance at the end of the term. At December 31, 2017 Enerplus was fully undrawn on the facility (December 31, 2016 - $23.2 million drawn). During 2017, a fee of $0.5 million (2016 - $0.7 million, 2015 - $0.3 million) was paid to extend the facility.

Senior Notes

During 2017, Enerplus made a principal repayment of US$22 million on its 2009 senior notes. During 2016, Enerplus repurchased US$267 million in outstanding senior notes at a discount, resulting in gains of $19.3 million.

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

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)	CDN$ Carrying Value ($ thousands)
September 3, 2014	March 3 and Sept 3	5 equal annual installments beginning September 3, 2022	3.79%	US$200,000	US$105,000	$ 131,996
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2019	4.34%	CDN$30,000	CDN$30,000	30,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	25,142
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	374,616
June 18, 2009	June 18 and Dec 18	4 equal annual installments beginning June 18, 2018 - 2021	7.97%	US$225,000	US$88,000	110,625
					Total carrying value	$ 672,379

8) ASSET RETIREMENT OBLIGATION

($ thousands)	December 31, 2017	December 31, 2016
Balance, beginning of year	$ 181,700	$ 206,359
Change in estimates	13,064	5,496
Property acquisition and development activity	1,322	3,003
Divestments	(72,306)	(35,635)
Settlements	(12,907)	(8,390)
Accretion expense	6,863	10,867
Balance, end of year	$ 117,736	$ 181,700

Enerplus has estimated the present value of its asset retirement obligation to be $117.7 million at December 31, 2017 based on a total undiscounted liability of $318.8 million (December 31, 2016 - $181.7 million and $452.1 million, respectively). The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.73% and inflation rate of 1.8% (December 31, 2016 – 5.86% and 1.7%, respectively). The majority of Enerplus' asset retirement obligation expenditures are expected to be incurred between 2025 and 2055.

9) OIL AND NATURAL GAS SALES

($ thousands)	2017	2016	2015
Oil and natural gas sales	$ 1,141,770	$ 882,126	$ 1,052,382
Royalties[1]	(221,077)	(159,394)	(167,990)
Oil and natural gas sales, net of royalties	$ 920,693	$ 722,732	$ 884,392

(1) Royalties above do not include production taxes which are reported separately on the Consolidated Statements of Income/(Loss).

10) GENERAL AND ADMINISTRATIVE EXPENSE

($ thousands)	2017	2016	2015
General and administrative expense	$ 50,544	$ 59,773	$ 81,312
Share-based compensation expense[1]	23,757	26,546	22,558
General and administrative expense	$ 74,301	$ 86,319	$ 103,870

(1) Includes cash and non-cash share-based compensation.

11) FOREIGN EXCHANGE

($ thousands)	2017	2016	2015
Realized:			
Foreign exchange (gain)/loss	$ 1,495	$ 108	$ (8,705)
Translation of U.S. dollar cash held in Canada	10,978	—	—
Unrealized:			
Translation of U.S. dollar debt and working capital (gain)/loss	(42,623)	(40,634)	160,791
Foreign exchange swap (gain)/loss	—	—	21,847
Foreign exchange (gain)/loss	$ (30,150)	$ (40,526)	$ 173,933

12) INCOME TAXES

Enerplus' provision for income tax is as follows:

($ thousands)	2017	2016	2015
Current tax expense/(recovery)			
Canada	$ (407)	$ (661)	$ (795)
United States	(47,550)	(1,690)	(16,092)
Current tax expense/(recovery)	(47,957)	(2,351)	(16,887)
Deferred tax expense/(recovery)			
Canada	$ (17,127)	$ (23,714)	$ (52,603)
United States	147,072	(211,133)	(97,985)
Deferred tax expense/(recovery)	129,945	(234,847)	(150,588)
Income tax expense/(recovery)	$ 81,988	$ (237,198)	$ (167,475)

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

($ thousands)	2017	2016	2015
Income/(loss) before taxes			
Canada	$ 146,953	$ 121,257	$ (500,113)
United States	172,033	38,961	(1,190,765)
Total income/(loss) before taxes	318,986	160,218	(1,690,878)
Canadian statutory rate	27.00%	27.00%	27.00%
Expected income tax expense/(recovery)	$ 86,126	$ 43,259	$ (456,537)
Impact on taxes resulting from:			
Change in valuation allowance	$ (162,992)	$ (266,896)	$ 443,655
Foreign and statutory rate differences	157,320	(12,826)	(179,809)
Non-taxable capital (gains)/losses	(6,337)	(6,478)	23,450
Share-based compensation	5,067	6,611	4,395
Other	2,804	(868)	(2,629)
Income tax expense/(recovery)	$ 81,988	$ (237,198)	$ (167,475)

Deferred income tax asset consists of the following temporary differences:

As at December 31 ($ thousands)	2017	2016
Deferred income tax assets		
Property, plant and equipment	$ 132,879	$ 257,105
Tax loss carry-forwards and other credits	397,081	571,166
Capital loss carryforwards and other capital items	181,334	187,986
Asset retirement obligation	31,677	50,462
Derivative financial assets and liabilities	8,795	10,515
Other assets	3,046	3,996
Deferred income tax asset before valuation allowance	754,812	1,081,230
Valuation allowance	(184,875)	(347,867)
Deferred income tax asset	$ 569,937	$ 733,363

For the year ended December 31, 2017, due to the enactment of the U.S. Tax Cuts and Jobs Act on December 22, 2017, Enerplus recorded $46.2 million in deferred income tax expense resulting from the remeasurement of the U.S. deferred income tax assets for the U.S. federal income tax rate reduction from 35% to 21%, offset by the reversal of the valuation allowance previously recorded on the AMT credit carryovers.

As of December 31, 2017, $50.1 million was reclassified from deferred income tax asset to income tax receivable for the AMT refund expected to be realized in 2018 (December 31, 2016 - nil).

Loss carry-forwards and tax credits available for tax reporting purposes:

As at December 31 ($ thousands)	2017	Expiration Date
Canada		
Capital losses	$ 1,223,000	Indefinite
Non-capital losses	395,000	2028-2037
United States		
Net operating losses	$ 854,000	2030-2037
Alternative minimum tax credits	100,000	Recoverable 2018-2021

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

($ thousands)	2017	2016	2015
Balance, beginning of year	$ 13,300	$ 15,100	$ 17,000
Increase/(decrease) for tax positions of prior years	—	—	(300)
Settlements	—	(1,800)	(1,600)
Balance, end of year	$ 13,300	$ 13,300	$ 15,100

If recognized, all of Enerplus' unrecognized tax benefits as at December 31, 2017 would affect Enerplus' effective income tax rate. It is not anticipated that the amount of unrecognized tax benefits will significantly change during the next 12 months.

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

Jurisdiction	Taxation Years
Canada - Federal & Provincial	2006, 2012-2017
United States - Federal & State	2011-2017

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

13) SHAREHOLDERS' EQUITY

a) Share Capital

Authorized: unlimited number of common shares Issued: (thousands)	2017 Shares	2017 Amount	2016 Shares	2016 Amount	2015 Shares	2015 Amount
Balance, beginning of year	240,483	$ 3,365,962	206,539	$ 3,133,524	205,732	$ 3,120,002
Issued for cash:						
Public offering	—	—	33,350	230,115	—	—
Share issue costs (net of tax of $2,621)	—	—	—	(7,084)	—	—
Stock Option Plan	—	—	—	—	234	3,205
Non-cash:						
Share-based compensation - settled	1,646	20,984	594	9,407	573	10,050
Stock Option Plan - exercised	—	—	—	—	—	267
Balance, end of year	242,129	$ 3,386,946	240,483	$ 3,365,962	206,539	$ 3,133,524

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

For the year ended December 31, 2017 Enerplus declared dividends of $0.12 per weighted average common share totaling $29.0 million (December 31, 2016 - $0.16 per share and $35.4 million, December 31, 2015 - $0.64 per share and $132.0 million).

b) Share-based Compensation

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

($ thousands)	2017	2016	2015
Cash:			
Long-term incentive plans expense	$ 997	$ 3,114	$ 874
Non-Cash:			
Long-term incentive plans expense	22,576	26,951	18,878
Stock option plan expense	—	63	709
Equity swap (gain)/loss	184	(3,582)	2,097
Share-based compensation expense	$ 23,757	$ 26,546	$ 22,558

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

The following table summarizes the Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Deferred Share Unit ("DSU") activity for the twelve months ended December 31, 2017:

For the year ended December 31, 2017	Cash-settled LTI Plans	Equity-settled LTI Plans		Total
(thousands of units)	DSU	PSU	RSU	
Balance, beginning of year	306	2,442	2,698	5,446
Granted	62	835	828	1,725
Vested	—	(528)	(1,125)	(1,653)
Forfeited	—	(36)	(292)	(328)
Balance, end of year	368	2,713	2,109	5,190

Cash-settled LTI Plans

For the year ended December 31, 2017, the Company made cash payments of $0.1 million related to its cash-settled plans (2016 - $2.7 million, 2015 - $15.0 million).

As of December 31, 2017, a liability of $4.5 million (December 31, 2016 - $3.9 million) with respect to the DSU plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

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

At December 31, 2017 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized share-based compensation expense	$ 28,053	$ 12,323	$ 40,376
Unrecognized share-based compensation expense	12,977	4,905	17,882
Fair value	$ 41,030	$ 17,228	$ 58,258
Weighted-average remaining contractual term (years)	1.7	1.3	

(1) Includes estimated performance multipliers.

ii) Stock Option Plan

At December 31, 2017 all stock options are fully vested and all non-cash share-based compensation expense has been fully recognized.

The following table summarizes the stock option plan activity for the year ended December 31, 2017:

Year ended December 31, 2017	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding, beginning of year	5,900	$ 18.29
Forfeited	(414)	18.74
Options outstanding and exercisable, end of year	5,486	$ 18.25

At December 31, 2017, 5,485,525 options were exercisable at a weighted average exercise price of $18.25 with a weighted average remaining contractual term of 1.6 years, giving an aggregate intrinsic value of nil (December 31, 2016 - nil, December 31, 2015 - nil). The intrinsic value of options exercised during the year ended December 31, 2017 was nil (December 31, 2016 - nil, December 31, 2015 - $0.2 million).

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

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

(thousands, except per share amounts)	2017	2016	2015
Net income/(loss)	$ 236,998	$ 397,416	$ (1,523,403)
Weighted average shares outstanding - Basic	241,929	226,530	206,205
Dilutive impact of share-based compensation(1)	5,945	4,763	—
Weighted average shares outstanding - Diluted	247,874	231,293	206,205
Net income/(loss) per share			
Basic	$ 0.98	$ 1.75	$ (7.39)
Diluted	$ 0.96	$ 1.72	$ (7.39)

(1) For the year ended December 31, 2015, the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

14) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At December 31, 2017, senior notes had a carrying value of $672.4 million and a fair value of $687.2 million (December 31, 2016 - $745.6 million and $771.0 million, respectively).

There were no transfers between fair value hierarchy levels during the year.

b) Derivative Financial Instruments

The derivative financial assets and liabilities on the Consolidated Balance Sheets result from recording derivative financial instruments at fair value.

The following tables summarize the change in fair value for the respective years:

Gain/(Loss) ($ thousands)	December 31, 2017	December 31, 2016	December 31, 2015	Income Statement Presentation
Equity Swaps	$ (184)	$ 3,582	$ (2,097)	G&A expense
Electricity Swaps	639	1,135	(408)	Operating expense
Foreign Exchange Derivatives	—	—	(21,847)	Foreign exchange
Commodity Derivative Instruments:				
Oil	(5,445)	(96,238)	(99,790)	Commodity derivative
Gas	11,174	(13,505)	(45,194)	instruments
Total Unrealized Gain/(Loss)	$ 6,184	$ (105,026)	$ (169,336)	

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

($ thousands)	2017	2016	2015
Change in fair value gain/(loss)	$ 5,729	$ (109,743)	$ (144,984)
Net realized cash gain	8,581	80,346	287,708
Commodity derivative instruments gain/(loss)	$ 14,310	$ (29,397)	$ 142,724

The following table summarizes the fair values at the respective year ends:

	December 31, 2017			December 31, 2016	
	Assets	Liabilities		Liabilities	
($ thousands)	Current	Current	Long-term	Current	Long-term
Electricity Swaps	$ —	$ —	$ —	$ 641	$ —
Equity Swaps	—	2,119	—	1,044	891
Commodity Derivative Instruments:					
Oil	2,142	26,523	9,907	17,466	11,375
Gas	1,710	—	—	9,464	—
Total	$ 3,852	$ 28,642	$ 9,907	$ 28,615	$ 12,266

c) Risk Management

In the normal course of operations, Enerplus is exposed to various market risks, including commodity prices, foreign exchange, interest rates and equity prices, credit risk and liquidity risk.

i) Market Risk

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

Commodity Price Risk:

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

The following tables summarize Enerplus' price risk management positions at February 20, 2018:

Crude Oil Instruments:

Instrument Type[(1)]	**bbls/day**	**US$/bbl[(1)]**
Jan 1, 2018 – Jan 31, 2018		
WTI Swap	5,000	55.38
WTI Purchased Put	13,000	53.04
WTI Sold Call	13,000	61.99
WTI Sold Put	13,000	42.83
WCS Differential Swap (Sale)	1,500	(14.75)
Feb 1, 2018 – Mar 31, 2018		
WTI Swap	7,000	58.32
WTI Purchased Put	13,000	53.04
WTI Sold Call	13,000	61.99
WTI Sold Put	13,000	42.83
WCS Differential Swap (Sale)	1,500	(14.75)
Apr 1, 2018 – Jun 30, 2018		
WTI Swap	5,000	55.38
WTI Purchased Put	15,000	52.90
WTI Sold Call	15,000	61.73
WTI Sold Put	15,000	42.92
WCS Differential Swap (Sale)	1,500	(14.75)
WCS Differential Swap (Purchase)	1,500	(25.50)
Jul 1, 2018 – Sep 30, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	18,000	52.53
WTI Sold Call	18,000	61.22
WTI Sold Put	18,000	42.71
WCS Differential Swap (Sale)	1,500	(14.75)
WCS Differential Swap (Purchase)	1,500	(25.50)
Oct 1, 2018 – Dec 31, 2018		
WTI Swap	3,000	53.73
WTI Purchased Put	20,000	52.48
WTI Sold Call	20,000	61.10
WTI Sold Put	20,000	42.74
WCS Differential Swap (Sale)	1,500	(14.75)
WCS Differential Swap (Purchase)	1,500	(25.50)
Jan 1, 2019 – Mar 31, 2019		
WTI Swap	3,000	53.73
WTI Purchased Put	16,000	53.69
WTI Sold Call	16,000	63.44
WTI Sold Put	16,000	44.05
Apr 1, 2019 – Dec 31, 2019		
WTI Purchased Put	20,000	53.94
WTI Sold Call	20,000	63.84
WTI Sold Put	20,000	44.09

(1) Transactions with a common term have been aggregated and presented as the weighted average price/bbl.

Natural Gas Instruments:

Instrument Type[1]	MMcf/day	US$/Mcf
Jan 1, 2018 – Mar 31, 2018		
NYMEX Purchased Put	30.0	2.75
NYMEX Sold Call	30.0	3.47
Apr 1, 2018 – Oct 31, 2018		
NYMEX Purchased Put	40.0	2.75
NYMEX Sold Call	40.0	3.38
Nov 1, 2018 – Dec 31, 2018		
NYMEX Purchased Put	30.0	2.75
NYMEX Sold Call	30.0	3.47

(1) Transactions with a common term have been aggregated and presented as the weighted average price/Mcf.

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, U.S. dollar denominated senior notes, cash deposits and working capital. Additionally, Enerplus' crude oil sales and a significant portion of its natural gas sales are based on U.S. dollar indices. To mitigate exposure to fluctuations in foreign exchange, Enerplus may enter into foreign exchange derivatives. At December 31, 2017 Enerplus did not have any foreign exchange derivatives outstanding.

During 2015, Enerplus recognized $39.2 million in net foreign exchange losses on the settlement of its foreign exchange collars and forward rate swaps, gains of $39.9 million on the unwind of its foreign exchange swaps on US$175 million of its US$225 million senior notes, and gains of $3.3 million on the settlement of its foreign exchange swap on the final principal repayment of its US$54 million senior notes.

Interest Rate Risk:

At December 31, 2017, all of Enerplus' debt was based on fixed interest rates, and Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 13. Enerplus has entered into various equity swaps maturing in 2018 and has effectively fixed the future settlement cost on 470,000 shares at a weighted average price of $16.89 per share.

ii) Credit Risk

Credit risk represents the financial loss Enerplus would experience due to the potential non-performance of counterparties to its financial instruments. Enerplus is exposed to credit risk mainly through its joint venture, marketing and financial counterparty receivables.

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

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At December 31, 2017, approximately 78% of Enerplus' marketing receivables were with companies considered investment grade.

Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at December 31, 2017 was $3.5 million (December 31, 2016 - $3.3 million).

iii) Liquidity Risk & Capital Management

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

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

At December 31, 2017, Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

15) COMMITMENTS AND CONTINGENCIES

a) Commitments

Enerplus has the following minimum annual commitments at December 31, 2017:

		Minimum Annual Commitment Each Year					
($ thousands)	Total	2018	2019	2020	2021	2022	Thereafter
Senior notes[1]	$ 672,379	$ 27,656	$ 57,656	$ 102,579	$ 102,579	$ 126,464	$ 255,445
Transportation commitments	249,214	28,106	26,490	22,652	19,804	17,715	134,447
Processing commitments	26,317	10,143	3,506	3,174	1,519	1,519	6,456
Drilling and completions	66,096	50,948	7,574	7,574	—	—	—
Office lease commitments	74,940	11,831	10,448	10,647	10,676	10,728	20,610
Sublease recoveries	(16,790)	(3,073)	(3,247)	(3,133)	(2,971)	(1,956)	(2,410)
Net office lease commitments[4]	58,150	8,758	7,201	7,514	7,705	8,772	18,200
Total commitments[2][3]	$ 1,072,156	$ 125,611	$ 102,427	$ 143,493	$ 131,607	$ 154,470	$ 414,548

(1) Interest payments have not been included.
(2) Crown and surface royalties, production taxes, lease rentals and mineral taxes (hydrocarbon production rights) have not been included as amounts paid depend on future ownership, production, prices and the legislative environment.
(3) US$ commitments have been converted to CDN$ using the December 31, 2017 foreign exchange rate of 1.2571.
(4) Net office lease payments in 2017 were $9.7 million (2016 - $10.5 million, 2015 - $10.8 million).

b) Contingencies

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

16) GEOGRAPHICAL INFORMATION

As at and for the year ended December 31, 2017 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 227,031	$ 693,662	$ 920,693
Depletion, depreciation and accretion	89,936	160,838	250,774
Property, plant and equipment	246,604	653,427	900,031
Goodwill	451,121	187,757	638,878
Income tax receivable	—	50,108	50,108

As at and for the year ended December 31, 2016 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 233,391	$ 489,341	$ 722,732
Depletion, depreciation and accretion	126,062	202,902	328,964
Property, plant and equipment	304,048	434,382	738,430
Goodwill	451,121	200,542	651,663
Income tax receivable	—	—	—

As at and for the year ended December 31, 2015 ($ thousands)	Canada	U.S.	Total
Oil and natural gas sales, net of royalties	$ 369,559	$ 514,833	$ 884,392
Depletion, depreciation and accretion	198,641	309,538	508,179
Property, plant and equipment	435,604	750,669	1,186,273
Goodwill	451,121	206,710	657,831
Income tax receivable	—	—	—

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

($ thousands)	December 31, 2017	December 31, 2016	December 31, 2015
Accounts receivable	$ (66,860)	$ 16,982	$ 37,064
Other current assets	(154)	2,154	(2,634)
Accounts payable	31,982	(4,061)	(47,260)
	$ (35,032)	$ 15,075	$ (12,830)

b) Changes in Other Non-Cash Working Capital

($ thousands)	December 31, 2017	December 31, 2016	December 31, 2015
Non-cash financing activities(1)	$ 16	$ (3,791)	$ (12,320)
Non-cash investing activities(2)	$ 1,523	$ (49,472)	$ (47,586)

(1) Relates to changes in dividends payable and included in dividends on the Consolidated Statements of Cash Flows.
(2) Relates to changes in accounts payable for capital and office expenditures and included in capital and office expenditures on the Consolidated Statements of Cash Flows.

c) Other

($ thousands)	December 31, 2017	December 31, 2016	December 31, 2015
Income taxes paid/(received)	$ 2,640	$ (21,244)	$ (22,274)
Interest paid	$ 38,149	$ 48,545	$ 65,498

5 YEAR DETAILED STATISTICAL REVIEW

	2017	2016	2015	2014	2013
Daily Production Volumes[1]					
Crude oil (bbls/day)	36,935	38,353	41,639	40,208	38,250
Natural gas liquids (bbls/day)	3,858	4,903	4,763	3,565	3,472
Natural gas (Mcf/day)	263,506	299,214	360,733	356,142	288,423
BOE per day	84,711	93,125	106,524	103,130	89,793
Drilling Activity (net wells)	46	25	46	88	62
Average Benchmark Pricing					
WTI Crude oil (US$ per bbl)	$ 50.95	$ 43.32	$ 48.80	$ 93.00	$ 97.97
AECO natural gas - monthly (per Mcf)	2.43	2.09	2.77	4.42	3.16
NYMEX natural gas - last day (US$ per Mcf)	3.11	2.46	2.66	4.41	3.65
US/CDN exchange rate (average)	1.30	1.32	1.28	1.10	1.03
Realized Pricing					
Crude oil[2] (per bbl)	$ 58.69	$ 44.84	$ 48.43	$ 86.28	$ 85.05
Natural gas liquids[2] (per bbl)	30.01	15.29	18.06	51.72	53.20
Natural gas [2] (per Mcf)	3.21	2.06	2.15	3.94	3.42
Financial ($ thousands, except per share amounts)					
Oil and natural gas sales[2]	$ 1,141,770	$ 882,126	$ 1,052,381	$ 1,849,312	$ 1,616,795
Adjusted funds flow	524,064	305,605	493,101	859,020	754,233
Cash flow from operating activities	476,125	312,290	465,336	787,197	766,478
Cash and stock dividends to Shareholders	29,033	35,439	131,955	221,098	216,864
Per share	0.12	0.16	0.64	1.08	1.08
Capital spending	458,015	209,135	493,403	811,026	681,437
Property and land acquisitions	13,276	126,126	9,552	18,491	244,837
Property Divestitures	56,196	670,364	286,614	203,576	365,135
Total net capital expenditures[3]	417,755	(333,627)	220,813	632,883	567,607
Total assets	2,645,832	2,638,850	2,581,234	4,031,492	3,681,799
Total debt, net cash and restricted cash	325,831	375,520	1,216,184	1,134,894	1,022,308
Adjusted payout ratio[4]	93%	80%	128%	118%	114%
Net debt/adjusted funds flow ratio	0.6x	1.2x	2.5x	1.3x	1.4x
Oil and Gas Economics					
Net royalty rate	24%	22%	21%	23%	21%
Average realized price[2]	$ 36.93	$ 25.88	$ 27.07	$ 49.13	$ 49.32
Transportation Costs	(3.60)	(3.14)	(2.95)	(2.69)	(1.77)
Royalties & Production Tax	(8.91)	(5.77)	(5.63)	(10.75)	(10.21)
Cash gains commodity derivative instruments	0.28	2.36	7.40	0.09	0.81
Average realized price, net	24.70	19.33	25.89	35.78	38.15
Cash operating expense	(6.39)	(7.31)	(8.75)	(9.23)	(9.94)
Operating netback, after hedging	18.31	12.02	17.14	26.55	28.21
Cash general and administrative expense	(1.66)	(1.84)	(2.11)	(2.19)	(3.25)
Cash interest, foreign exchange and other expenses	(1.24)	(1.28)	(2.78)	(1.42)	(1.71)
Current tax	1.55	0.07	0.43	(0.12)	(0.24)
Adjusted funds flow	$ 16.96	$ 8.97	$ 12.68	$ 22.82	$ 23.01
Trading Information					
Canadian trading summary[5]					
High	$ 13.35	$ 13.55	$ 16.09	$ 27.05	$ 19.96
Low	$ 8.97	$ 2.68	$ 4.24	$ 9.02	$ 12.26
Close	$ 12.31	$ 12.74	$ 4.75	$ 11.19	$ 19.30
Volume	520,460	688,243	550,742	360,805	214,057
U.S. trading summary[6]					
High	$ 10.21	$ 10.33	$ 13.16	$ 25.37	$ 18.79
Low	$ 6.52	$ 1.84	$ 3.01	$ 7.75	$ 12.03
Close	$ 9.79	$ 9.48	$ 3.42	$ 9.60	$ 18.18
Volume	261,215	347,941	382,094	203,965	192,733
Weighted average number of shares outstanding (basic)[7]	241,929	226,530	206,205	204,510	200,567
Number of shares outstanding at December 31[7]	242,129	240,483	206,539	205,732	202,758

(1) Production is on a company interest basis.
(2) Before transportation, royalties and the effects of commodity derivative instruments.
(3) Includes office capital.
(4) Calculated as the sum of cash dividends to shareholders, office capital and capital spending, divided by adjusted funds flow.
(5) Canadian composite trading data including TSX thereafter. Volumes are in thousands.
(6) U.S. composite trading data including NYSE thereafter. Volumes are in thousands.
(7) All shares are in thousands.

($ thousands)	2017	2016	2015	2014	2013
Reserves [(1)]					
Proved Reserves					
Crude oil (Mbbls)	122,543	119,419	131,778	127,007	118,611
NGLs (Mbbls)	13,000	11,825	10,704	8,137	8,967
Conventional natural gas (MMcf)	55,992	95,769	183,564	331,709	409,830
Shale gas (MMcf)	803,018	726,614	625,081	564,583	411,431
MBOE	278,711	268,308	277,255	284,525	264,455
Probable Reserves					
Crude oil (Mbbls)	68,479	56,798	58,222	73,424	73,635
NGLs (Mbbls)	7,752	6,273	4,993	4,662	5,757
Conventional natural gas (MMcf)	21,289	30,521	53,802	124,721	183,744
Shale gas (MMcf)	233,742	276,169	338,288	275,357	189,430
MBOE	118,737	114,186	128,563	144,766	141,587
Proved Plus Probable Reserves					
Crude oil (Mbbls)	191,022	176,216	189,999	200,431	192,246
NGLs (Mbbls)	20,752	18,098	15,697	12,798	14,723
Conventional natural gas (MMcf)	77,281	126,290	237,366	456,430	593,574
Shale gas (MMcf)	1,036,760	1,002,783	963,368	839,940	600,861
MBOE	397,448	382,493	405,818	429,291	406,042
Reserves Life Index[(2)]					
Proved (years)	9.2	9.0	9.0	7.8	7.6
Proved plus probable (years)	12.6	12.3	12.2	10.7	10.8
Finding & Development Costs and Finding, Development & Acquisition Costs(3)					
Proved Reserves					
Finding & Development Costs					
Capital Expenditures	$ 458.0	$ 209.1	$ 493.4	$ 811.0	$ 681.4
Net change in Future Development Costs	$ 114.0	$ (124.4)	$ 210.0	$ 13.8	$ (106.4)
Gross Reserves additions (MMBOE)	50.5	47.2	50.7	69.1	57.1
F&D costs ($/BOE)	**$ 11.32**	**$ 1.79**	**$ 13.88**	**$ 11.94**	**$ 10.08**
Finding, Development & Acquisition Costs					
Capital Expenditures and net acquisitions	$ 415.1	$ (335.1)	$ 216.2	$ 625.9	$ 561.1
Net change in Future Development Costs	$ 96.7	$ (202.1)	$ 139.7	$ 4.9	$ (112.8)
Gross Reserves additions (MMBOE)	41.0	24.7	31.1	60.9	69.9
FD&A costs ($/BOE)	**$ 12.48**	**$ (21.74)**	**$ 11.44**	**$ 10.36**	**$ 6.41**
Proved Plus Probable Reserves					
Finding & Development Costs					
Capital Expenditures	$ 458.0	$ 209.1	$ 493.4	$ 811.0	$ 681.4
Net change in Future Development Costs	$ 102.8	$ (4.0)	$ (142.2)	$ (71.3)	$ 200.0
Gross Reserves additions (MMBOE)	58.0	42.6	41.6	75.5	78.1
F&D costs ($/BOE)	**$ 9.68**	**$ 4.82**	**$ 8.44**	**$ 9.80**	**$ 11.28**
Finding, Development & Acquisition Costs					
Capital Expenditures and net acquisitions	$ 415.1	$ (335.1)	$ 216.2	$ 625.9	$ 561.1
Net change in Future Development Costs	$ 85.1	$ (94.5)	$ (212.5)	$ (59.2)	$ 216.0
Gross Reserves additions (MMBOE)	45.6	10.3	14.9	65.8	93.0
FD&A costs ($/BOE)	**$ 10.98**	**$ (41.60)**	**$ 0.25**	**$ 8.62**	**$ 8.36**

(1) Reserves for 2014, 2015, 2016 & 2017 are based on gross reserves volumes. 2013 is based on company interest reserves volumes. Company interest reserves consist of gross reserves (as defined in National Instrument 51-101) plus the Company's royalty interests. Company interest reserves are not a term defined in National Instrument 51-101 and may not be comparable to reserves disclosed by other issuers.

(2) The Reserves Life Indices (RLI) are based upon year-end proved and proved plus probable reserves divided by the following year's proved and proved plus probable production volumes as forecast in the independent reserves engineering reports.

(3) Includes future development capital

NET ASSET VALUE

Enerplus' estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before taxes, as estimated by our independent reserves engineers, McDaniel and Netherland, Sewell & Associates, Inc. at year-end, plus the estimated value of our undeveloped acreage and other equity investments, less asset retirement obligations, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserves engineers.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development, including development of contingent resources. As we execute our capital programs, we expect to convert contingent resources to reserves which could result in a significant increase in our booked proved plus probable reserves. The land values described in the Net Asset Value table below do not necessarily reflect the full value of the contingent resources associated with these lands.

Net Asset Value (Forecast Prices and Costs at December 31, 2017)

($ millions, except per share amounts	0%	5%	10%	15%
Total net present value of proved plus probable reserves (before tax)	$ 8,880	$ 5,430	$ 3,811	$ 2,897
Undeveloped acreage (2017 year end)(1)	60	60	60	60
Asset retirement obligations(2)	(3)	(80)	(46)	(26)
Debt, net of cash and restricted cash	(326)	(326)	(326)	(326)
Net working capital(3)	(105)	(105)	(105)	(105)
Net Asset Value	$ 8,506	$ 4,979	$ 3,394	$ 2,500
Net Asset Value per Share(4)	$ 35.13	$ 20.56	$ 14.02	$ 10.32

(1) Canadian acreage in S.E. Saskatchewan is carried at market price. U.S. acreage is carried at historical acquisition cost. All other acreage is valued at a nominal value of $50/acre. U.S. values were converted to Canadian dollars using a US/CDN exchange rate of 1.2571.
(2) Asset retirement obligations ("ARO") may not equal the balance sheet as a portion of ARO costs are already reflected in the present value of 2P reserves, and the discount rates applied may differ.
(3) Net working capital includes current derivative financial assets and liabilities, excluding the current portion of long-term debt.
(4) Based on 242,128,944 shares outstanding as at December 31, 2017.

ABBREVIATIONS

AECO a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices

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

Bcf billion cubic feet

BcfGE(1) billion cubic feet of gas equivalent

BOE(1) barrels of oil equivalent

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

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

IFRS International Financial Reporting Standards

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMcf million cubic feet

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

MWh megawatt hour(s) of electricity

NGLs natural gas liquids

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

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

2P Reserves proved plus probable reserves

RLI reserves life index

SEC United States Securities and Exchange Commission

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

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

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

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

DEFINITIONS

Adjusted Payout Ratio Calculated as the sum of dividends to shareholders plus capital spending (including office capital) divided by adjusted funds flow.

Contingent Resources 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 economic, 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 project stage. “Economic” contingent resources are those resources that are economically recoverable based on McDaniel’s January 1, 2018 forecast prices.

The economic contingent resources estimates are presented as the “best estimate” of the quantity that will actually be recovered, meaning 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”.

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

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

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

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

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

Operating Income Calculated as revenues from oil and gas sales less cash hedging costs, transportation costs, royalties and operating costs.

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

Production, Gross Our working interest (operated and non-operated) share of production before the deduction of any royalty interest production. Unless otherwise stated, all production volumes utilized in any discussions or calculations are gross production volumes.

Reserves Life Index, Proved Calculated as proved reserves at year-end divided by the following year's estimated proved production volumes as determined by the independent reserves engineering report.

Reserves Life Index, Proved plus Probable Calculated as proved plus probable reserves at year-end divided by the following year's estimated proved plus probable production volumes as determined by the independent reserves engineering report.

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

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

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

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

Reserves, Developed Non-Producing Reserves that have either not been on production or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

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

Reserves, Undeveloped Reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production.

BOARD OF DIRECTORS

Elliott Pew[1][2]

Corporate Director
Boerne, Texas

David H. Barr[9][12]

Corporate Director
The Woodlands, Texas

Michael R. Culbert[3][5][10]

Corporate Director
Calgary, Alberta

Ian C. Dundas

President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Hilary A. Foulkes[3][7][9][11]

Corporate Director
Calgary, Alberta

Robert B. Hodgins[3][6]

Corporate Director
Calgary, Alberta

Susan M. MacKenzie[5][7][11]

Corporate Director
Calgary, Alberta

Glen D. Roane[4][5]

Corporate Director
Canmore, Alberta

Jeffrey W. Sheets[5][7]

Corporate Director
Houston, Texas

Sheldon B. Steeves[5][8]

Corporate Director
Calgary, Alberta

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

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas

President & Chief Executive Officer

Raymond J. Daniels

Senior Vice President, Operations, Corporate

Jodine J. Jenson Labrie

Senior Vice President & Chief Financial Officer

Eric G. Le Dain

Senior Vice President, Corporate Development, Commercial

Nathan D. Fisher

Vice President, U.S. Development & Geosciences

Daniel J. Fitzgerald

Vice President, Business Development

John E. Hoffman

Vice President, Canadian Operations

David A. McCoy

Vice President, General Counsel & Corporate Secretary

Edward L. McLaughlin

President, Enerplus U.S. Operations

Shaina B. Morihira

Vice President, Finance

CORPORATE INFORMATION

Operating Companies Owned by Enerplus Corporation

Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
KPMG LLP
Calgary, Alberta

Transfer Agent
Computershare Trust Company of Canada
Calgary, Alberta
Toll free: 1.866.921.0978

U.S. Co-Transfer Agent
Computershare Trust Company, N.A.
Golden, Colorado

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

Netherland, Sewell & Associates, Inc.
Dallas, Texas

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

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

Telephone: 720.279.5500
Fax: 720.279.5550

Annual Meeting
Shareholders are encouraged to attend the Annual Meeting being held on:

Thursday, May 3, 2018
1:00 p.m., MT
Bankers Hall Auditorium
P3 level, Bankers Hall
315 – 8th Avenue SW
Calgary, Alberta

Toll Free 1-800-319-6462
www.enerplus.com
investorrelations@enerplus.com

The Dome Tower
3000, 333-7th Avenue SW
Calgary, Alberta T2P 2Z1

ERF LISTED ON TMX Toronto Stock Exchange

ERF LISTED NYSE