Q2 2016

enerPLUS

SECOND QUARTER REPORT
SIX MONTHS ENDED JUNE 30, 2016

SELECTED FINANCIAL RESULTS	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Financial (000's)				
Funds Flow[4]	$ 76,047	$ 160,436	$ 117,774	$ 269,600
Dividends to Shareholders	6,547	30,935	21,011	78,294
Net Income/(Loss)	(168,554)	(312,544)	(342,220)	(605,750)
Debt Outstanding – net of cash	674,147	1,120,680	674,147	1,120,680
Capital Spending	48,120	147,979	91,396	314,989
Property and Land Acquisitions	343	(1,011)	3,897	(1,248)
Property Divestments	92,735	187,801	280,503	191,513
Debt to Funds Flow Ratio[4]	2.0x	1.6x	2.0x	1.6x
Financial per Weighted Average Shares Outstanding				
Net Income/(Loss)	$ (0.77)	$ (1.52)	$ (1.61)	$ (2.94)
Weighted Average Number of Shares Outstanding (000's)	218,128	206,208	212,420	206,028
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 24.96	$ 30.53	$ 21.99	$ 28.78
Royalties and Production Taxes	(5.51)	(6.23)	(4.72)	(5.88)
Commodity Derivative Instruments	2.53	7.47	3.51	8.48
Cash Operating Expenses	(7.20)	(8.12)	(7.67)	(8.81)
Transportation Costs	(2.87)	(2.87)	(2.88)	(2.89)
General and Administrative Expenses	(1.71)	(2.03)	(1.89)	(2.19)
Cash Share-Based Compensation	(0.09)	0.13	(0.09)	(0.32)
Interest, Foreign Exchange and Other Expenses	(1.21)	(2.48)	(1.51)	(2.87)
Current Income Tax Recovery	0.02	0.01	0.02	–
Funds Flow[4]	$ 8.92	$ 16.41	$ 6.76	$ 14.30

SELECTED OPERATING RESULTS	Three months ended June 30,		Six months ended June 30,	
	2016	2015	2016	2015
Average Daily Production[2]				
Crude Oil (bbls/day)	39,079	41,122	39,294	40,243
Natural Gas Liquids (bbls/day)	4,829	5,145	5,161	4,444
Natural Gas (Mcf/day)	298,503	366,971	307,827	356,836
Total (BOE/day)	93,659	107,429	95,759	104,160
% Crude Oil and Natural Gas Liquids	47%	43%	46%	43%
Average Selling Price[2][3]				
Crude Oil (per bbl)	$ 46.48	$ 58.26	$ 39.00	$ 51.35
Natural Gas Liquids (per bbl)	15.67	20.88	13.37	21.55
Natural Gas (per Mcf)	1.49	2.09	1.64	2.32
Net Wells Drilled	5	8	17	36

(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 June 30, 2016	2015	Six months ended June 30, 2016	2015
WTI crude oil (US$/bbl)	$ 45.59	$ 57.94	$ 39.52	$ 53.29
AECO natural gas – monthly index (CDN$/Mcf)	1.25	2.67	1.68	2.81
AECO natural gas – daily index (CDN$/Mcf)	1.40	2.64	1.62	2.70
NYMEX natural gas – last day (US$/Mcf)	1.95	2.64	2.02	2.81
USD/CDN average exchange rate	1.29	1.23	1.33	1.24

Share Trading Summary For the three months ended June 30, 2016	CDN[1] – ERF (CDN$)	U.S.[2] – ERF (US$)
High	$ 8.78	$ 6.94
Low	$ 4.68	$ 3.55
Close	$ 8.51	$ 6.57

(1) TSX and other Canadian trading data combined.

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

2016 Dividends per Share Payment Month	CDN$	US$[1]
First Quarter Total	$ 0.09	$ 0.06
April	$ 0.01	$ 0.01
May	0.01	0.01
June	0.01	0.01
Second Quarter Total	$ 0.03	$ 0.03
Total Year to Date	$ 0.12	$ 0.09

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

NEWS RELEASE

"We have significantly strengthened our balance sheet having reduced our debt, net of cash, by 45% since year-end 2015. In addition, we continue to drive costs lower as we position our company to deliver profitable growth in a lower commodity price environment," stated Ian C. Dundas, President & CEO. "Enerplus continues to perform at a high level operationally, and with our lower cost structure and improved financial strength we are modestly increasing our 2016 capital program in North Dakota as we position the company for growth in 2017."

Key Takeaways:

- Production averaged 93,659 BOE per day during the quarter, including 43,908 barrels per day of crude oil and natural gas liquids. Annual average 2016 production is tracking the higher-end of Enerplus' guidance range of 90,000 – 94,000 BOE per day, despite the divestment of approximately 2,300 BOE per day at the end of the second quarter, largely due to strong Marcellus production. As a result, Enerplus is updating its 2016 average production guidance to 92,000 – 94,000 BOE per day. Crude oil and natural gas liquids production guidance remains unchanged at 43,000 – 45,000 barrels per day.
- Enerplus has significantly strengthened its balance sheet in 2016. The receipt of divestment proceeds of $280.5 million year to date and net equity financing proceeds of $220.4 million, have helped reduce the Company's total debt net of cash by 45% since December 31, 2015. At June 30, 2016, Enerplus had $723.3 million of senior notes outstanding and $49.2 million in cash and the Company's $800 million bank credit facility was undrawn. At June 30, 2016, the Company's senior debt to adjusted EBITDA ratio was 1.2 times and debt to funds flow ratio was 2.0 times.
- Enerplus continued to deliver significant cost savings during the second quarter including a reduction in cash costs comprising operating, transportation, G&A and interest of $1.68 per BOE compared to the same period in 2015.
- Operating costs were $7.10 per BOE in the quarter, 10% lower than the same period in 2015 and below the Company's annual guidance of $8.50 per BOE as a result of continued cost reductions and the divestment of higher operating cost properties. Cash G&A expenses were $1.71 per BOE in the second quarter, 16% lower than the same period in 2015 and below the Company's annual guidance of $2.00 per BOE primarily due to a reduction in staffing levels. Based on this performance, Enerplus is reducing its 2016 guidance for operating expenses to $7.90 per BOE and cash G&A expenses to $1.95 per BOE.
- Enerplus recorded a net loss of $168.6 million or ($0.77) per share in the second quarter, which is attributable to non-cash items including an impairment charge and a deferred tax asset valuation allowance as a result of the continued decline in the twelve month trailing average commodity prices.
- Enerplus generated second quarter funds flow of $76.0 million, an increase of 82% from the previous quarter. The increased funds flow was driven by higher crude oil prices, improved commodity price differentials and lower cash costs.
- Enerplus' realized pricing differentials in the Bakken and Marcellus have meaningfully improved over the past year. Although in part this is due to lower benchmark prices, improvements in the supply-demand balance in each basin have also contributed to the tighter differentials. Compared to the same period in 2015, Enerplus' second quarter realized Bakken differential narrowed by US$1.07 per barrel to US$8.23 per barrel below WTI, and Enerplus' second quarter realized Marcellus differential narrowed by US$0.63 per Mcf averaging US$0.76 per Mcf below NYMEX.
- Capital spending in the second quarter was $48.1 million of which $30.4 million was directed to North Dakota. As a result of Enerplus' stronger financial position and lower cost structure, which is driving margin improvement, the Company is increasing its 2016 capital spending guidance to $215 million from $200 million to add three gross completions and pre-order facilities equipment in North Dakota during the latter part of the year for the 2017 program. The incremental expenditure will allow Enerplus to further test well downspacing in Fort Berthold, and is expected to add approximately 1,000 BOE per day to Enerplus' fourth quarter production volumes and better position the Company for growth in 2017. Enerplus continues to expect its 2016 capital and dividend commitments to be fully funded through internally generated cash flow at current forward strip commodity prices.

Asset Activity

North Dakota production averaged 28,800 BOE per day during the second quarter, largely flat from the previous quarter and up 6% from the same period in 2015. Enerplus continues to operate one drilling rig at Fort Berthold with capital spending in the quarter totaling $30.4 million resulting in 4.6 net wells drilled and 7.2 net wells on-stream. Well costs continue to trend down as a result of improvements in drilling time and ongoing completions optimization. Enerplus' average cost for a two-mile lateral well in the second quarter was US$7.8 million including drilling, completion, tie-in and facilities costs, 26% lower than the Company's 2015 average. Initial 30-day production rates from operated wells brought on-stream in the second quarter averaged approximately 1,450 BOE per day. At the end of the quarter, Enerplus had approximately 8 net drilled uncompleted wells in Fort Berthold.

Marcellus production averaged 195 MMcf per day during the second quarter, a modest increase from the first quarter of 2016. Capital spending in the Marcellus was $9.3 million in the quarter delivering 0.3 net wells drilled and 1.8 net wells on-stream. The production increase over the previous quarter was due to strong well performance. Enerplus participated in 7 gross on-stream wells in the second quarter with initial 30-day production rates that averaged 15.8 MMcf per day and an average lateral length of 6,400 ft. Enerplus continues to plan for limited activity levels in the Marcellus for the remainder of 2016.

Production from the Canadian waterflood assets averaged 16,560 BOE per day during the second quarter of 2016, 5% lower than the previous quarter. Lower second quarter production was due to limited capital activity levels and the divestment of certain non-core assets located in northwest Alberta in June 2016. In the second quarter, Enerplus spent approximately $7.1 million on waterflood optimization activities. Enerplus will continue to focus on cost management in these assets which is helping to deliver strong operating netbacks.

Production and Capital Spending

	Three months ended June 30, 2016		Six months ended June 30, 2016	
	Average Production Volumes	Capital Spending ($ millions)	Average Production Volumes	Capital Spending ($ millions)
Crude Oil & NGLs (bbls/day)				
Canada	14,915	7.1	15,453	26.2
United States	28,993	31.6	29,002	52.3
Total Crude Oil & NGLs (bbls/day)	**43,908**	**38.7**	**44,455**	**78.5**
Natural Gas (Mcf/day)				
Canada	79,878	0.1	89,708	0.1
United States	218,625	9.3	218,119	12.8
Total Natural Gas (Mcf/day)	**298,503**	**9.4**	**307,827**	**12.9**
Company Total (BOE/day)	**93,659**	**48.1**	**95,759**	**91.4**

Net Drilling Activity(1) – for the three months ended June 30, 2016

	Wells Drilled	Wells On-stream
Crude Oil		
Canada	–	–
United States	4.6	7.2
Total Crude Oil	**4.6**	**7.2**
Natural Gas		
Canada	–	–
United States	0.3	1.8
Total Natural Gas	**0.3**	**1.8**
Company Total	**4.9**	**9.1**

(1) Table may not add due to rounding

Crude Oil & Natural Gas Pricing

Enerplus' average crude oil selling price during the second quarter was $46.48 per barrel, an increase of 47% compared to the prior quarter as a result of the higher benchmark crude oil prices and narrowing Canadian differentials. Benchmark West Texas Intermediate (WTI) crude oil prices increased by 36% quarter-over-quarter to average US$45.59 per barrel in the second quarter. Enerplus' realized pricing outperformed benchmark WTI prices as light and heavy crude differentials in Canada improved by 16% and 7% respectively, compared to the previous quarter, due to industry wide production outages resulting from the severe wildfires in northern Alberta. These outages also supported U.S. Bakken crude differentials which improved by 2% quarter-over-quarter.

Enerplus' average natural gas selling price during the second quarter was $1.49 per Mcf, 16% lower than the prior quarter, reflecting the significant weakness experienced in Western Canadian gas prices during the period. Benchmark NYMEX gas prices fell by 7% in the second quarter, while in Canada benchmark AECO monthly natural gas prices were 41% weaker than in the first quarter of 2016 in large part due to excessive inventory levels caused by mild winter weather. Supported by Enerplus' AECO basis hedging contracts, the Company's realized Canadian gas price differential significantly outperformed the AECO benchmark price, averaging US$0.86 per Mcf below NYMEX during the quarter compared to the benchmark AECO monthly differential of US$0.99 per Mcf below NYMEX.

Enerplus' realized Marcellus differential improved by 16% during the second quarter to average US$0.76 per Mcf below NYMEX. Industry rig counts in the Marcellus region have fallen meaningfully over the past year which has moderated Northeast Pennsylvania production growth and improved price differentials to NYMEX. Enerplus expects its Marcellus differential to widen in the third quarter with stronger NYMEX prices.

Risk Management

Enerplus continues to protect a portion of funds flow through commodity hedging. Based on 2016 forecast net oil production after royalties, Enerplus has approximately 39% of volumes protected in the second half of 2016 and 2017 through collar structures. Based on 2016 forecast net natural gas production after royalties, Enerplus has approximately 29% and 20% of volumes protected in the second half of 2016 and 2017 respectively, through a combination of swaps and collar structures.

Commodity Hedging Detail (as at July 22, 2016)

	WTI Crude Oil (US$/bbl)[(1)]		NYMEX Natural Gas (US$/Mcf)[(1)]		
	Jul 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017	Jul 1, 2016 – Oct 31, 2016	Nov 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017
Swaps					
Sold Swaps	–	–	$ 2.53	$ 2.48	–
Volume (bbl/d or Mcf/d)	–	–	50,000	25,000	–
% of net production	–	–	22%	11%	–
3 Way Collars					
Sold Puts	$ 45.09	$ 38.59	$ 2.50	$ 2.50	$ 2.03
Volume (bbl/d or Mcf/d)	12,000	12,000	25,000	25,000	45,000
% of net production	39%	39%	11%	11%	20%
Purchased Puts	$ 57.82	$ 50.00	$ 3.00	$ 3.00	$ 2.72
Volume (bbl/d or Mcf/d)	12,000	12,000	25,000	25,000	45,000
% of net production	39%	39%	11%	11%	20%
Sold Calls	$ 71.75	$ 60.50	$ 3.75	$ 3.75	$ 3.37
Volume (bbl/d or Mcf/d)	12,000	12,000	25,000	25,000	45,000
% of net production	39%	39%	11%	11%	20%

(1) Based on weighted average price (before premiums), assuming average annual production of 93,000 BOE/day for 2016 and 2017, less royalties and production taxes of 22% in aggregate

2016 Revised Guidance

Enerplus has revised its full year 2016 guidance to reflect stronger natural gas production from the Marcellus, a lower expected overall royalty expense, reduced operating and G&A expenses, and a modest increase in capital spending to support 2017 growth.

Summary of 2016 Expectations	Revised Guidance	Previous Guidance
Capital spending	$215 million	$200 million
Average annual production	92,000 – 94,000 BOE/day	90,000 – 94,000 BOE/day
Crude oil and natural gas liquids volumes	43,000 – 45,000 barrels/day	43,000 – 45,000 barrels/day
Average royalty and production tax rate	22%	23%
Operating expenses	$7.90/BOE	$8.50/BOE
Transportation expense	$3.10/BOE	$3.10/BOE
Cash G&A expenses	$1.95/BOE	$2.00/BOE

Currency and Accounting Principles

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

Barrels of Oil Equivalent

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

Presentation of Production Information

Under U.S. GAAP oil and gas sales are generally presented net of royalties and U.S. industry protocol is to present production volumes net of royalties. Under Canadian industry protocol oil and gas sales and production volumes are presented on a gross basis before deduction of royalties. In order to continue to be comparable with its Canadian peer companies, the summary results contained within this news release presents Enerplus' production and BOE measures on a before royalty company interest basis. All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest.

Readers are cautioned that the average initial production rates contained in this news release are not necessarily indicative of long-term performance or of ultimate recovery.

Forward-Looking Information and Statements

This news release 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", "should", "believe", "plans", "budget", "strategy" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the foregoing, this news release contains forward-looking information pertaining to the following: expected 2016 average production volumes and the anticipated production mix; the proportion of anticipated oil and gas production that is hedged and the effectiveness of such hedges in protecting funds flow; the results from drilling programs and the timing of related production; oil and natural gas prices and differentials and commodity and foreign exchange risk management programs in 2016 and in 2017; expectations regarding realized oil and natural gas prices; anticipated cash and non-cash G&A, share based compensation and financing expenses; operating and transportation costs; capital spending levels in 2016, anticipated drilling and completions program, and the expected impact on production levels; potential future asset impairments; future debt and working capital levels and debt to funds flow ratios.

The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that Enerplus will conduct its operations and achieve results of operations as anticipated; that Enerplus' development plans will achieve the expected results; current commodity price 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 Enerplus' reserves and resources volumes; the continued availability of adequate debt and/or equity financing, cash flow and other sources to fund Enerplus' capital and operating requirements, and dividend payments as needed; availability of third party services; and the extent of its liabilities. In addition, Enerplus' 2016 revised guidance is based on the following assumptions: WTI crude oil price of US$42.61/bbl, NYMEX gas price of US$2.46/Mcf, and AECO gas price of $2.00/GJ, and USD/CDN exchange rate of 1.32. 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 news release is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes, including future decline, in commodity prices; changes in realized prices for Enerplus' products; changes in the demand for or supply of Enerplus' products; unanticipated operating results, results from Enerplus' capital spending activities or production declines; curtailment of Enerplus' 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 development plans by Enerplus or by third party operators of Enerplus' properties; increased debt levels or debt service requirements; Enerplus' inability to comply with covenants under its bank credit facility and senior notes; changes in estimates of Enerplus' oil and gas reserves and resources volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners; failure to complete any anticipated acquisitions or divestitures; and certain other risks detailed from time to time in Enerplus' public disclosure documents (including, without limitation, those risks identified in its AIF and Form 40-F at December 31, 2015).

Non-GAAP Measures

In this news release, we use the terms "funds flow" and "debt to funds flow ratio" as measures to analyze operating performance, leverage and liquidity. "Funds flow" is calculated as net cash generated from operating activities but before changes in non-cash operating working capital and asset retirement obligation expenditures. "Debt to funds flow ratio" is calculated as total debt net of cash, divided by a trailing 12 months of funds flow. In addition, "senior debt to adjusted EBITDA" is used to determine Enerplus' compliance with financial covenants under its bank credit facility and outstanding senior notes. Calculation of these terms is described in Enerplus Corporation's Second Quarter 2016 MD&A under the "Liquidity and Capital Resources" section.

Enerplus believes that, in addition to net earnings and other measures prescribed by U.S. GAAP, the terms "funds flow" and "debt to funds flow" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures, and "senior debt to adjusted EBITDA" measures, are not measures recognized by U.S. GAAP and do not have a standardized meaning prescribed by U.S.GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers. For reconciliation of these measures to the most directly comparable measure calculated in accordance with U.S. GAAP, and further information about these measures, see disclosure under "Non-GAAP Measures" in Enerplus' Second Quarter 2016 MD&A.

Electronic copies of Enerplus Corporation's Second Quarter 2016 MD&A and Financial Statements, along with other public information including investor presentations, are available on its website at www.enerplus.com. Shareholders may, upon request, receive a printed copy of our audited financial statements at any time. For further information, please contact Investor Relations at 1-800-319-6462 or email investorrelations@enerplus.com.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of financial results is dated August 4, 2016 and is to be read in conjunction with:

- the unaudited interim consolidated financial statements of Enerplus Corporation ("Enerplus" or the "Company") as at and for the three and six months ended June 30, 2016 and 2015 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2015 and 2014 and for the years ended December 31, 2015, 2014 and 2013; and
- our MD&A for the year ended December 31, 2015 (the "Annual MD&A").

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 the MD&A for further information.

BASIS OF PRESENTATION

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

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. BOE and Mcfe measures 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.

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

OVERVIEW

During the second quarter, we continued to position ourselves to deliver profitable growth in a low commodity price environment. The proceeds from our equity issuance and the ongoing success of our non-core asset divestment program allowed us to significantly reduce our debt and strengthen our balance sheet. Operationally, our assets continue to deliver strong results with improving cost structures.

On May 31, 2016, we completed an equity financing for 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million net of issue costs). Our non-core asset divestment program continued to provide significant liquidity, with proceeds of $92.7 million during the second quarter and total proceeds of approximately $280.5 million to date in 2016. These proceeds were used to fully repay our drawn credit facility and fund the repurchase of an additional US$95 million of our senior notes during the quarter, for a total repurchase of US$267 million of senior notes to date, at prices ranging from 90% of par to par value. Through these steps we have reduced our total debt net of cash by 45% to $674.1 million at June 30, 2016 from $1,216.2 million at December 31, 2015.

Average daily production for the second quarter was 93,659 BOE/day, at the high end of our annual average production guidance range, and as a result we are increasing the low end of our annual guidance range to 92,000 BOE/day, with the upper end remaining at 94,000 BOE/day. We continue to expect to produce approximately 43,000 – 45,000 bbls/day of crude oil and natural gas liquids. Production decreased approximately 4% from the first quarter of 2016 largely due to the first quarter sale of our Canadian Deep Basin natural gas properties, along with overall decline in Canadian production volumes as a result of lower capital spending. Production volumes in the U.S. remained flat compared to the prior quarter, with the impact of lower capital spending offset by strong performance in the Marcellus and Fort Berthold areas.

We maintained a disciplined capital program, spending $48.1 million during the second quarter and $91.4 million year to date, with the majority directed to our Fort Berthold properties. We are modestly increasing our spending in Fort Berthold during the second half of the year to position ourselves for growth in 2017. We plan to spend an additional $15 million on three gross completions and pre-spending on facilities, and are projecting our fourth quarter production to increase by approximately 1,000 BOE/day. As a result, we are increasing our 2016 capital guidance to $215 million from $200 million, which is expected to be funded through internally generated cash flow at current forward strip commodity prices.

Operating expenses came in below guidance of $8.50/BOE, totaling $60.5 million or $7.10/BOE during the second quarter. The decrease in operating costs was mainly due to the ongoing success of our cost savings initiatives, reduced activity levels and continued improvement in pricing for materials and services, along with the divestment of higher cost Canadian properties. As a result, we are reducing our annual guidance for operating expenses to $7.90/BOE from $8.50/BOE. Cash G&A expenses were also below guidance, totaling $14.6 million or $1.71/BOE compared to guidance of $2.00/BOE, primarily due to a reduction in staff levels. Accordingly, we are revising our annual cash G&A expense guidance to $1.95/BOE from $2.00/BOE.

Our commodity hedging program continued to provide funds flow protection, contributing cash gains of $21.6 million in the second quarter. We added additional downside protection during the second quarter, and as of July 22, 2016, we have approximately 39% of our forecasted 2016 crude oil production, net of royalties, hedged for the remainder of 2016 and 2017. We have also hedged approximately 29% of our forecasted 2016 natural gas production, net of royalties, for the remainder of 2016 and approximately 20% for 2017.

We recorded a net loss of $168.6 million and funds flow of $76.0 million for the quarter. Second quarter earnings included gains of $74.7 million on asset divestments and $12.2 million on the repurchase of senior notes. These gains were offset by a non-cash impairment charge of $148.7 million and a non-cash valuation allowance on our deferred tax asset of $105.0 million as a result of the decline in the twelve month trailing average commodity prices.

RESULTS OF OPERATIONS

Production

Production for the second quarter totaled 93,659 BOE/day, at the high end of our annual average guidance range of 90,000 – 94,000 BOE/day. Compared to production in the first quarter of 2016 of 97,860 BOE/day, production decreased 4% primarily due to the first quarter sale of Canadian Deep Basin natural gas properties with production of approximately 5,400 BOE/day.

Production in the second quarter of 2016 decreased 13% from production levels of 107,429 BOE/day in the same period of 2015 primarily due to the sale of non-core properties with production of approximately 9,000 BOE/day during the second half of 2015 and the first quarter of 2016. This excludes the June sale of approximately 2,300 BOE/day of non-core Canadian assets. Production volumes from our Canadian assets were further impacted by the reduction in capital spending in 2015 and 2016, while strong performance from our U.S. assets offset any decline due to lower spending.

As a result of the sale of the Deep Basin natural gas properties and other non-core Canadian shallow gas properties, our crude oil and natural gas liquids weighting increased to 47% of our total average daily production in the second quarter of 2016, from 46% in the first quarter of 2016 and 43% in the second quarter of 2015.

Average daily production volumes for the three and six months ended June 30, 2016 and 2015 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2016**	**2015**	**% Change**	**2016**	**2015**	**% Change**
Crude oil (bbls/day)	39,079	41,122	(5%)	39,294	40,243	(2%)
Natural gas liquids (bbls/day)	4,829	5,145	(6%)	5,161	4,444	16%
Natural gas (Mcf/day)	298,503	366,971	(19%)	307,827	356,836	(14%)
Total daily sales (BOE/day)	93,659	107,429	(13%)	95,759	104,160	(8%)

As a result of strong performance and higher natural gas prices expected in the Marcellus, and despite the sale of approximately 2,300 BOE/day of non-core assets in June, we are increasing the lower end of our average annual production guidance to 92,000 – 94,000 BOE/day from 90,000 – 94,000 BOE/day. We are maintaining our annual crude oil and natural gas liquids production guidance of 43,000 – 45,000 bbls/day. This guidance does not include any additional acquisitions or divestments.

Pricing

The prices received for our crude oil and natural gas production directly impact our earnings, funds flow and financial condition. The following table compares average prices from the first half of 2016 to the first half of 2015 and other periods indicated:

	Six months ended June 30,						
Pricing (average for the period)	**2016**	**2015**	**Q2 2016**	**Q1 2016**	**Q4 2015**	**Q3 2015**	**Q2 2015**
Benchmarks							
WTI crude oil (US$/bbl)	$ 39.52	$ 53.29	$ 45.59	$ 33.45	$ 42.18	$ 46.43	$ 57.94
AECO natural gas – monthly index ($/Mcf)	1.68	2.81	1.25	2.11	2.65	2.80	2.67
AECO natural gas – daily index ($/Mcf)	1.62	2.70	1.40	1.83	2.47	2.90	2.64
NYMEX natural gas – last day (US$/Mcf)	2.02	2.81	1.95	2.09	2.27	2.77	2.64
USD/CDN average exchange rate	1.33	1.24	1.29	1.37	1.34	1.31	1.23
USD/CDN period end exchange rate	1.30	1.25	1.30	1.30	1.38	1.34	1.25
Enerplus selling price[1]							
Crude oil ($/bbl)	$ 39.00	$ 51.35	$ 46.48	$ 31.59	$ 43.04	$ 48.22	$ 58.26
Natural gas liquids ($/bbl)	13.37	21.55	15.67	11.34	16.61	13.51	20.88
Natural gas ($/Mcf)	1.64	2.32	1.49	1.77	1.89	2.08	2.09
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (3.39)	$ (4.93)	$ (3.09)	$ (3.69)	$ (2.44)	$ (3.42)	$ (3.06)
WCS Hardisty – WTI (US$/bbl)	(13.77)	(13.16)	(13.30)	(14.24)	(14.50)	(13.27)	(11.59)
Transco Leidy monthly – NYMEX (US$/Mcf)	(0.84)	(1.63)	(0.70)	(0.99)	(1.15)	(1.66)	(1.50)
TGP Z4 300L monthly – NYMEX (US$/Mcf)	(0.90)	(1.67)	(0.73)	(1.07)	(1.23)	(1.75)	(1.57)
AECO monthly – NYMEX (US$/Mcf)	(0.76)	(0.54)	(0.99)	(0.56)	(0.28)	(0.63)	(0.47)
Enerplus realized differentials[1]							
Canada crude oil – WTI (US$/bbl)	$ (13.46)	$ (14.13)	$ (12.01)	$ (14.14)	$ (13.63)	$ (11.82)	$ (12.50)
Canada natural gas – NYMEX (US$/Mcf)	(0.74)	(0.46)	(0.86)	(0.63)	(0.42)	(0.43)	(0.46)
Bakken crude oil – WTI (US$/bbl)	(8.29)	(10.05)	(8.23)	(8.38)	(7.93)	(8.52)	(9.30)
Marcellus natural gas – NYMEX (US$/Mcf)	(0.83)	(1.35)	(0.76)	(0.91)	(1.13)	(1.64)	(1.39)

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

CRUDE OIL AND NATURAL GAS LIQUIDS

Our average realized crude oil price during the second quarter was $46.48/bbl, an increase of 47% compared to the prior quarter as a result of the higher benchmark crude oil prices and narrowing Canadian differentials. WTI crude oil prices increased by 36% to average US$45.59/bbl in the quarter due to improving seasonal demand for crude oil in the U.S. combined with lower overall U.S. production. Canadian light and heavy crude oil differentials improved by 16% and 7%, respectively, when compared to the previous quarter, due to industry wide production outages resulting from the severe wildfires in northern Alberta. These outages also helped U.S. Bakken crude oil differentials to improve by 2%. In the second quarter our realized natural gas liquids price increased by 38% compared to the first quarter, in-line with the increases in benchmark crude oil and liquids prices during the quarter.

NATURAL GAS

Our average realized natural gas price during the second quarter was $1.49/Mcf, 16% lower when compared to the prior quarter. Benchmark NYMEX and AECO monthly natural gas prices in the second quarter fell by 7% and 41%, respectively, compared to the previous quarter due to high inventory levels as a result of one of the warmest winters on record. Approximately 33% of our second quarter Canadian gas production was sold under fixed basis contracts. As a result, our realized Canadian natural gas price differential significantly outperformed the AECO benchmark price, averaging US$0.86/Mcf below NYMEX during the quarter compared to the benchmark AECO monthly differential of US$0.99/Mcf below NYMEX.

Industry rig counts in the Marcellus region have fallen dramatically over the past year, resulting in lower production growth in Northeast Pennsylvania and improved price differentials to NYMEX. Monthly differentials at Transco Leidy and TGP Zone 4 300 Leg improved by 29% and 32%, respectively, compared to the prior quarter and 53% compared to the second quarter of 2015. In comparison, our realized Marcellus differential improved by 16% during the second quarter, and 45% compared to the same period last year, to average US$0.76/Mcf below NYMEX. With a portion of our second quarter natural gas sales exposed to other regional prices that were seasonally weaker, our Marcellus realized differential did not improve as much as the local Leidy and TGP benchmarks.

FOREIGN EXCHANGE

The Canadian dollar strengthened throughout the second quarter as a result of higher crude oil prices. The USD/CDN exchange rate was 1.30 USD/CDN at June 30, 2016, and averaged 1.29 USD/CDN during the second quarter compared to 1.37 USD/CDN during the first quarter. 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 fluctuations in the Canadian dollar also impact our U.S. dollar denominated costs, capital spending and the reported value of our U.S. dollar denominated debt.

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. Since our first quarter, we have added additional floor protection on a portion of our oil and natural gas production for 2016 and 2017.

As of July 22, 2016, we have hedged 12,000 bbls/day of our expected crude oil production for the remainder of 2016 and 2017, which represents approximately 39% of our forecasted 2016 net crude oil production, after royalties. Price protection levels are shown in the table below. For the second half of 2016 and the full year of 2017, we have floor protection at an effective price of US$57.82/bbl and US$50.00/bbl, respectively. When WTI prices settle below the sold put strike price in any given month, the three way collars provide protection of approximately US$12.73/bbl and US$11.41/bbl above the WTI index prices in 2016 and 2017, respectively. Overall, we expect our crude oil related hedge contracts to protect a significant portion of our funds flow.

As of July 22, 2016, we have hedged approximately 66,700 Mcf/day of our expected natural gas production for the remainder of 2016 consisting of a combination of NYMEX swaps and collars. This represents approximately 29% of our forecasted natural gas production, after royalties. For 2017 we have hedged 45,000 Mcf/day or approximately 20% of our forecasted 2016 natural gas production, after royalties, using three way collars. Price protection levels are shown in the table below. With regards to the NYMEX three way collars, when NYMEX prices settle below the sold put strike price in any given month, the three way collars provide protection of approximately US$0.50/Mcf and US$0.69/Mcf above the NYMEX index price in 2016 and 2017, respectively.

The following is a summary of our financial contracts in place at July 22, 2016, expressed as a percentage of our anticipated net 2016 production volumes:

	WTI Crude Oil (US$/bbl)[(1)]		NYMEX Natural Gas (US$/Mcf)[(1)]		
	Jul 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017	Jul 1, 2016 – Oct 31, 2016	Nov 1, 2016 – Dec 31, 2016	Jan 1, 2017 – Dec 31, 2017
Sold Swaps	–	–	$ 2.53	$ 2.48	–
%	–	–	22%	11%	–
Three Way Collars					
Sold Puts	$ 45.09	$ 38.59	$ 2.50	$ 2.50	$ 2.03
%	39%	39%	11%	11%	20%
Purchased Puts	$ 57.82	$ 50.00	$ 3.00	$ 3.00	$ 2.72
%	39%	39%	11%	11%	20%
Sold Calls	$ 71.75	$ 60.50	$ 3.75	$ 3.75	$ 3.37
%	39%	39%	11%	11%	20%

(1) Based on weighted average price (before premiums), assuming average annual production of 93,000 BOE/day for 2016 and 2017 less royalties and production taxes of 22% in aggregate.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses)	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Cash gains/(losses):				
Crude oil	$ 16.4	$ 56.7	$ 52.9	$ 127.2
Natural gas	5.2	16.4	8.3	32.7
Total cash gains/(losses)	$ 21.6	$ 73.1	$ 61.2	$ 159.9
Non-cash gains/(losses):				
Crude oil	$ (27.2)	$ (71.1)	$ (58.4)	$ (107.1)
Natural gas	(16.3)	(21.8)	(11.2)	(22.2)
Total non-cash gains/(losses)	$ (43.5)	$ (92.9)	$ (69.6)	$ (129.3)
Total gains/(losses)	$ (21.9)	$ (19.8)	$ (8.4)	$ 30.6

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2016	2015	2016	2015
Total cash gains/(losses)	$ 2.53	$ 7.47	$ 3.51	$ 8.48
Total non-cash gains/(losses)	(5.10)	(9.49)	(3.99)	(6.85)
Total gains/(losses)	$ (2.57)	$ (2.02)	$ (0.48)	$ 1.63

During the second quarter of 2016 we realized cash gains of $16.4 million on our crude oil contracts and $5.2 million on our natural gas contracts. In comparison, during the second quarter of 2015 we realized cash gains of $56.7 million on our crude oil contracts and $16.4 million on our natural gas contracts. The cash gains were due to contracts which provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the second quarter of 2016 the fair value of our crude oil contracts represented a net gain position of $9.0 million, while our natural gas contracts represented a net loss position of $7.2 million. For the three and six months ended June 30, 2016, the change in the fair value of our crude oil contracts represented losses of $27.2 million and $58.4 million, respectively, and our natural gas contracts represented losses of $16.3 million and $11.2 million, respectively.

Revenues

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Oil and natural gas sales	$ 212.7	$ 298.4	$ 383.2	$ 542.5
Royalties	(38.4)	(46.7)	(66.2)	(85.8)
Oil and natural gas sales, net of royalties	$ 174.3	$ 251.7	$ 317.0	$ 456.7

Oil and natural gas revenues for the three and six months ended June 30, 2016 were $212.7 million and $383.2 million, respectively, a decrease of 31% from the same periods in 2015. The decrease in revenue was a result of the decline in oil and natural gas prices over the respective periods, as well as the impact of lower production volumes.

Royalties and Production Taxes

($ millions, except per BOE amounts)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Royalties	$ 38.4	$ 46.7	$ 66.2	$ 85.8
Per BOE	$ 4.51	$ 4.78	$ 3.80	$ 4.55
Production taxes	$ 8.6	$ 14.2	$ 16.0	$ 25.0
Per BOE	$ 1.00	$ 1.45	$ 0.92	$ 1.33
Royalties and production taxes	$ 47.0	$ 60.9	$ 82.2	$ 110.8
Per BOE	$ 5.51	$ 6.23	$ 4.72	$ 5.88
Royalties and production taxes (% of oil and natural gas sales)	22%	20%	21%	20%

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. A large percentage of our production is from U.S. properties where royalty rates are generally not as sensitive to commodity price levels. During the three and six months ended June 30, 2016, royalties and production taxes decreased to $47.0 million and $82.2 million, respectively, from $60.9 million and $110.8 million for the same periods in 2015, primarily due to lower realized prices and lower production volumes. Royalties and production taxes averaged 21% of oil and natural gas sales before transportation costs in the first half of 2016 compared to 20% for the same period in 2015 due to increased production from our U.S. properties.

We have revised our average royalty and production tax rate guidance to 22% of oil and gas sales for 2016 from 23%. We do not expect the recently announced Alberta modernized royalty framework to have a significant impact on our Canadian royalties.

Operating Expenses

($ millions, except per BOE amounts)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Cash operating expenses	$ 61.4	$ 79.3	$ 133.7	$ 166.2
Non-cash (gains)/losses[(1)]	(0.9)	(2.6)	(0.6)	(1.7)
Total operating expenses	$ 60.5	$ 76.7	$ 133.1	$ 164.5
Per BOE	$ 7.10	$ 7.85	$ 7.64	$ 8.72

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

For the three and six months ended June 30, 2016, operating expenses were $60.5 million and $133.1 million, respectively, a decrease of 21% and 19% compared to the same periods in 2015. On a per BOE basis, operating costs for the three and six months ended June 30, 2016 were $7.10/BOE and $7.64/BOE, outperforming our annual guidance of $8.50/BOE. The decrease in operating costs was mainly a result of our continued cost saving initiatives and the divestment of higher operating cost Canadian properties over the last year.

Based on cost savings to date, we are reducing our 2016 guidance for operating expenses to $7.90/BOE from $8.50/BOE.

Transportation Costs

($ millions, except per BOE amounts)	Three months ended June 30, 2016	2015	Six months ended June 30, 2016	2015
Transportation costs	$ 24.5	$ 28.0	$ 50.2	$ 54.5
Per BOE	$ 2.87	$ 2.87	$ 2.88	$ 2.89

For the three and six months ended June 30, 2016, transportation costs were $24.5 million ($2.87/BOE) and $50.2 million ($2.88/BOE), respectively, compared to $28.0 million ($2.87/BOE) and $54.5 million ($2.89/BOE) for the same periods in 2015. The decrease in transportation costs was primarily due to lower production.

We are maintaining our 2016 guidance for transportation costs of $3.10/BOE. Although year to date transportation costs are below our annual guidance, effective August 2016 we have firm transportation commitments for 30,000 Mcf/day of additional interstate pipeline capacity from the Marcellus region to downstream connections at pricing of US$0.71/Mcf.

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.

	Three months ended June 30, 2016		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	46,972 BOE/day	280,122 Mcfe/day	93,659 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 40.57	$ 1.54	$ 24.96
Royalties and production taxes	(9.57)	(0.24)	(5.51)
Cash operating expenses	(10.04)	(0.73)	(7.20)
Transportation costs	(1.85)	(0.64)	(2.87)
Netback before hedging	$ 19.11	$ (0.07)	$ 9.38
Cash gains/(losses)	3.83	0.20	2.53
Netback after hedging	$ 22.94	$ 0.13	$ 11.91
Netback before hedging ($ millions)	$ 81.6	$ (1.8)	$ 79.8
Netback after hedging ($ millions)	$ 98.0	$ 3.4	$ 101.4

	Three months ended June 30, 2015		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	49,058 BOE/day	350,226 Mcfe/day	107,429 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 52.17	$ 2.06	$ 30.53
Royalties and production taxes	(12.15)	(0.21)	(6.23)
Cash operating expenses	(11.27)	(0.91)	(8.12)
Transportation costs	(1.68)	(0.64)	(2.87)
Netback before hedging	$ 27.07	$ 0.30	$ 13.31
Cash gains/(losses)	12.69	0.52	7.47
Netback after hedging	$ 39.76	$ 0.82	$ 20.78
Netback before hedging ($ millions)	$ 121.0	$ 9.2	$ 130.2
Netback after hedging ($ millions)	$ 177.6	$ 25.7	$ 203.3

	Six months ended June 30, 2016		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	47,836 BOE/day	287,538 Mcfe/day	95,759 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 33.82	$ 1.70	$ 21.99
Royalties and production taxes	(7.95)	(0.25)	(4.72)
Cash operating expenses	(10.06)	(0.88)	(7.67)
Transportation costs	(1.85)	(0.65)	(2.88)
Netback before hedging	$ 13.96	$ (0.08)	$ 6.72
Cash gains/(losses)	6.08	0.16	3.51
Netback after hedging	$ 20.04	$ 0.08	$ 10.23
Netback before hedging ($ millions)	$ 121.5	$ (4.4)	$ 117.1
Netback after hedging ($ millions)	$ 174.5	$ 3.8	$ 178.3

Netbacks by Property Type	Six months ended June 30, 2015 Crude Oil	Natural Gas	Total
Average Daily Production	46,916 BOE/day	343,464 Mcfe/day	104,160 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 46.98	$ 2.31	$ 28.78
Royalties and production taxes	(10.99)	(0.28)	(5.88)
Cash operating expenses	(12.31)	(0.99)	(8.81)
Transportation costs	(1.82)	(0.63)	(2.89)
Netback before hedging	$ 21.86	$ 0.41	$ 11.20
Cash gains/(losses)	14.98	0.53	8.48
Netback after hedging	$ 36.84	$ 0.94	$ 19.68
Netback before hedging ($ millions)	$ 185.6	$ 25.4	$ 211.0
Netback after hedging ($ millions)	$ 312.9	$ 58.0	$ 370.9

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

Crude oil and natural gas netbacks per BOE decreased for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily due to lower commodity prices and lower realized hedging gains. Our crude oil properties accounted for substantially all of our netback, both before and after hedging.

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") and our stock option plan. See Note 10 and Note 14 to the Interim Financial Statements for further details.

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Cash:				
G&A expense	$ 14.6	$ 19.9	$ 33.0	$ 41.3
Share-based compensation expense	0.8	(1.2)	1.5	6.0
Non-Cash:				
Share-based compensation expense	5.4	4.6	8.9	9.6
Equity swap loss/(gain)	(1.6)	1.0	(1.7)	(0.6)
Total G&A expenses	$ 19.2	$ 24.3	$ 41.7	$ 56.3

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2016	2015	2016	2015
Cash:				
G&A expense	$ 1.71	$ 2.03	$ 1.89	$ 2.19
Share-based compensation expense	0.09	(0.13)	0.09	0.32
Non-Cash:				
Share-based compensation expense	0.63	0.47	0.51	0.51
Equity swap loss/(gain)	(0.18)	0.11	(0.10)	(0.03)
Total G&A expenses	$ 2.25	$ 2.48	$ 2.39	$ 2.99

For the three and six months ended June 30, 2016, cash G&A expenses were $14.6 million ($1.71/BOE) and $33.0 million ($1.89/BOE), respectively, compared to $19.9 million ($2.03/BOE) and $41.3 million ($2.19/BOE) for the same periods in 2015. The decrease in cash G&A expenses from the prior year was primarily due to a 30% reduction in staff levels throughout 2015 and to date in 2016, offset by one-time severance payments, as we continue to respond to the current commodity price environment.

During the quarter, our share price increased by 67% resulting in a cash SBC expense of $0.8 million ($0.09/BOE) compared to a recovery of $1.2 million ($0.13/BOE) in the same period of 2015. We recorded non-cash SBC of $5.4 million ($0.63/BOE) in the second quarter compared to $4.6 million ($0.47/BOE) during the same period in 2015. The increase in non-cash SBC was due to the additional expense related to the 2016 grant.

We have hedged a portion of the outstanding cash settled grants under our LTI plans. As a result of the increase in our share price during the quarter we recorded a non-cash mark-to-market gain of $1.6 million on these hedges. As of June 30, 2016 we had 470,000 units hedged at a weighted average price of $16.89 per share.

Based on our continued focus on costs, we are reducing our 2016 guidance for cash G&A expenses to $1.95/BOE from $2.00/BOE.

Interest Expense

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Interest on senior notes and bank facility	$ 10.0	$ 15.9	$ 24.6	$ 32.7
Non-cash interest expense	0.6	0.2	0.8	0.5
Total interest expense	$ 10.6	$ 16.1	$ 25.4	$ 33.2

For the three and six months ended June 30, 2016, we recorded total interest expense of $10.6 million and $25.4 million, respectively, compared to $16.1 million and $33.2 million for the same periods in 2015. The decrease in interest expense corresponds to a decrease in the aggregate principal amount of our outstanding senior notes following our repurchase of US$267 million of senior notes during the first half of 2016. The repurchase of senior notes was funded by asset divestment proceeds and lower interest rate bank debt, which was repaid in full following our May 31, 2016 equity financing and the closing of our previously announced Canadian non-core asset divestment.

At June 30, 2016, our bank credit facility was undrawn, and our debt balance consisted solely of fixed interest rate senior notes with a weighted average interest rate of 5.0%.

Foreign Exchange

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Realized loss/(gain)	$ 0.3	$ 8.4	$ 2.0	$ (27.2)
Unrealized loss/(gain)	0.1	(36.1)	(56.0)	103.7
Total foreign exchange loss/(gain)	$ 0.4	$ (27.7)	$ (54.0)	$ 76.5
USD/CDN average exchange rate	1.29	1.23	1.33	1.24

For the three and six months ended June 30, 2016, we recorded a net foreign exchange loss of $0.4 million and a net foreign exchange gain of $54.0 million, respectively, compared to a gain of $27.7 million and a loss of $76.5 million for the same periods in 2015. Realized losses related to day-to-day transactions recorded in foreign currencies. During the six months ended June 30, 2015 we recorded realized gains of $27.2 million primarily due to a $39.9 million gain on the unwind of certain foreign exchange swaps offset by losses on our foreign exchange collars.

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 June 30, 2016 to December 31, 2015, the Canadian dollar strengthened relative to the U.S. dollar resulting in unrealized gains of $56.0 million. See Note 12 to the Interim Financial Statements for further details.

Capital Investment

($ millions)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Capital spending	$ 48.1	$ 148.0	$ 91.4	$ 315.0
Office capital	0.1	1.4	0.1	2.3
Sub-total	48.2	149.4	91.5	317.3
Property and land acquisitions	$ 0.3	$ (1.0)	$ 3.9	$ (1.2)
Property divestments	(92.7)	(187.8)	(280.5)	(191.5)
Sub-total	(92.4)	(188.8)	(276.6)	(192.7)
Total	$ (44.2)	$ (39.4)	$ (185.1)	$ 124.6

Capital spending for the three and six months ended June 30, 2016, totaled $48.1 million and $91.4 million, respectively, compared to $148.0 million and $315.0 million for the same periods in 2015. The decrease is in-line with our reduced spending program for 2016, as we continue to invest modestly in our core areas. During the second quarter we spent $30.4 million on our Fort Berthold crude oil properties, $7.1 million on our Canadian crude properties and $9.4 million on our Marcellus assets.

In June 2016, we completed the previously announced sale of non-core properties in northwest Alberta for proceeds of $92.7 million, net of closing costs, with estimated 2016 production of approximately 2,300 BOE/day. In comparison, during the second quarter of 2015, we sold non-core assets with proceeds of $187.8 million, including our Pembina waterflood assets. Year to date, we have recorded total proceeds on asset divestments of $280.5 million, compared to $191.5 million in the same period of 2015.

We are increasing our 2016 capital guidance by $15 million to $215 million to begin to position ourselves for growth in 2017. The incremental capital will be directed to Fort Berthold, and includes the addition of three gross completions as well as pre-spending on our facilities during the second half of the year. We expect the additional spending to increase our fourth quarter production by approximately 1,000 BOE/day and to be funded through internally generated cash flow at current forward strip commodity prices.

Gain on Asset Sales and Note Repurchases

We recorded a gain of $74.7 million on the sale of non-core Canadian properties during the second quarter of 2016, bringing our year to date gain on asset divestments to $219.8 million. Under full cost accounting rules, divestitures 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 the second quarter of 2016, we recorded a gain of $12.2 million on the repurchase of US$95 million of outstanding senior notes at a discount to par value. Year to date, we have repurchased a total of US$267 million of senior notes at prices between 90% of par and par value, resulting in a total gain of $19.3 million.

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

($ millions, except per BOE amounts)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
DD&A expense	$ 82.3	$ 137.4	$ 173.5	$ 269.8
Per BOE	$ 9.66	$ 14.06	$ 9.95	$ 14.31

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and six months ended June 30, 2016, DD&A decreased when compared the same periods of 2015 primarily due to the cumulative effects of asset impairments recorded during 2015 and the first quarter of 2016.

Impairment

Under U.S. GAAP, the full cost ceiling test is performed on a country-by-country basis using estimated after-tax future net cash flows discounted at 10 percent from proved reserves using SEC constant prices ("Standardized Measure"). SEC prices are calculated as the unweighted average of the trailing twelve first-day-of-the-month commodity prices. The Standardized Measure is not related to Enerplus' 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 continued to decline in the first half of 2016 but less significantly than in 2015. Non-cash impairments of $148.7 million and $194.9 million were recorded for the three and six months ended June 30, 2016, respectively, compared to $497.2 million and $764.9 million in the same periods of 2015.

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 remainder of this 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 trailing twelve month average commodity prices are near current levels, there is the potential for prices to decline further during 2016, impacting the ceiling value and resulting in further non-cash impairments. See Note 5 to the Interim Financial Statements for trailing twelve month prices.

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 our net ownership interest and management's estimate of 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 $188.2 million at June 30, 2016, compared to $206.4 million at December 31, 2015. For the three and six months ended June 30, 2016, asset retirement obligation settlements were $0.8 million and $3.2 million, respectively, compared to $2.6 million and $6.5 million during the same periods in 2015. As a result of our divestments to date in 2016, we have reduced our asset retirement obligation by $22.6 million.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Current tax expense/(recovery)	$ (0.2)	$ (0.1)	$ (0.4)	$ –
Deferred tax expenses/(recovery)	53.3	(221.7)	309.8	(360.1)
Total tax expense/(recovery)	$ 53.1	$ (221.8)	$ 309.4	$ (360.1)

For the three and six months ended June 30, 2016 we recorded total tax expense of $53.1 million and $309.4 million, respectively, compared to a tax recovery of $221.8 million and $360.1 million for the same periods in 2015. The current quarter expense includes an additional valuation allowance of $105.0 million recorded against our deferred income tax asset, partially offset by a recovery due to the non-cash asset impairment expense recorded in the U.S. and Canada. We assess the recoverability of our deferred income tax assets each period to determine whether it is more likely than not that all or a portion of our deferred income tax assets will be realized. Our assessment is primarily based on a projection of undiscounted future taxable income using historical trailing twelve month benchmark prices. After recording the valuation allowance, our overall net deferred income tax asset was $186.7 million at June 30, 2016 compared to $516.1 million at December 31, 2015.

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 under our bank credit facility and senior notes, 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. At June 30, 2016, our senior debt to adjusted EBITDA ratio was 1.2x and our debt to funds flow ratio was 2.0x. Although it is not included in our debt covenants, the debt to funds flow ratio is often used by investors and analysts to evaluate our liquidity.

We have continued to be diligent in managing and preserving our financial position. On May 31, 2016 we completed an equity financing for 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230.1 million ($220.4 million net of issue costs). Our non-core asset divestment program continued to provide significant liquidity, with proceeds of $92.7 million during the second quarter and total proceeds of approximately $280.5 million to date in 2016. These proceeds were used to fully repay our drawn credit facility and fund the repurchase of US$95 million of our senior notes during the quarter, and a total of US$267 million of senior notes to date. The senior note repurchases were completed at prices ranging from 90% of par to par value, resulting in a total gain of $19.3 million for the six months ended June 30, 2016. Furthermore, as a result of the note repurchases we expect to save approximately US$13 million in interest expense on an annualized basis.

Following the equity financing and non-core asset divestments, total debt net of cash at June 30, 2016 was $674.1 million, a decrease of 45% compared to $1,216.2 million at December 31, 2015. At June 30, 2016, we had $723.3 million of senior notes outstanding less $49.2 million in cash and our $800 million bank credit facility was undrawn.

We continued to maintain our financial flexibility through an ongoing focus on cost efficiencies and disciplined capital spending. Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by funds flow, was 72% and 96% for the three and six months ended June 30, 2016, compared to 112% and 147% for the same periods in 2015. After adjusting for net acquisition and divestment proceeds, we had a funding surplus of $282.0 million for the six months ended June 30, 2016.

Our working capital deficiency, excluding cash and current deferred financial assets and liabilities, decreased to $88.5 million at June 30, 2016 from $104.0 million at December 31, 2015. We expect to finance our working capital deficit and our ongoing working capital requirements through cash, funds flow and our bank credit facility. We have sufficient liquidity to meet our financial commitments, as disclosed under "Commitments" in the Annual MD&A.

At June 30, 2016, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Based on our current guidance, we expect to manage our business within these financial ratios; however, current oil and gas prices have created a significant level of uncertainty which may challenge the assumptions and estimates used in management's forecast. If we exceed any of the covenants, we may be required to repay, refinance or renegotiate the terms of the debt. If we reach or exceed these covenant thresholds, there are a number of steps that may be taken to improve them, including asset divestments, a reduction to capital spending and equity issuances.

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 as at June 30, 2016:

Covenant Description		June 30, 2016
Bank Credit Facility:	**Maximum Ratio**	
Senior debt to adjusted EBITDA[1]	3.5 x	1.2 x
Total debt to adjusted EBITDA	4.0 x	1.2 x
Total debt to capitalization	50%	29%
Senior Notes:	**Maximum Ratio**	
Senior debt to adjusted EBITDA[2]	3.0 x – 3.5 x	1.2 x
Senior debt to consolidated present value of total proved reserves[3]	60%	32%
	Minimum Ratio	
Adjusted EBITDA to interest	4.0 x	10.3 x

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.

"Adjusted EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, impairment and other non-cash gains and losses. Adjusted EBITDA is calculated on a trailing twelve month basis and is adjusted for material acquisitions and divestments. Adjusted EBITDA for the three months and the trailing twelve months ended June 30, 2016 were $170.7 million and $603.2 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) See "Non-GAAP Measures" in this MD&A for a reconciliation of adjusted EBITDA to net income.
(2) Senior debt to adjusted EBITDA may increase to 3.5x for a period of 6 months for the senior notes, after which the ratio decreases to 3.0x.
(3) Senior 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%.

Dividends

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per share amounts)	2016	2015	2016	2015
Dividends to shareholders	$ 6.5	$ 30.9	$ 21.0	$ 78.3
Per weighted average share (Basic)	$ 0.03	$ 0.15	$ 0.10	$ 0.38

During the three and six months ended June 30, 2016, we reported total dividends of $6.5 million or $0.03 per share and $21.0 million or $0.10 per share, respectively, compared to $30.9 million or $0.15 per share and $78.3 million or $0.38 per share for the same periods in 2015.

Effective with the April 2016 payment, we reduced the monthly dividend by 67% from $0.03 per share to $0.01 per share to provide additional financial flexibility and to balance funds flow with capital and dividends. The dividend is an important part of our strategy to create shareholder value and we will continue to monitor commodity prices and economic conditions and are prepared to make adjustments as necessary.

Shareholders' Capital

	Six months ended June 30,	
	2016	2015
Share capital ($ millions)	$ 3,366.0	$ 3,126.6
Common shares outstanding (thousands)	240,483	206,224
Weighted average shares outstanding – basic (thousands)	212,420	206,028
Weighted average shares outstanding – diluted (thousands)	212,420	206,028

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).

During the second quarter no shares were issued pursuant to the stock option plan and the treasury settled LTI plans, resulting in no additional equity for the company (2015 – 45,000; $0.6 million). For the six months ended June 30, 2016 a total of 594,000 shares were issued pursuant to the treasury settled Restricted Share Unit plan resulting in $9.4 million of additional equity (2015 – 492,000; $6.3 million). For further details see Note 14 to the Interim Financial Statements.

At August 4, 2016 we had 240,483,000 shares outstanding.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

	Three months ended June 30, 2016			Three months ended June 30, 2015		
($ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	13,497	25,582	39,079	15,462	25,660	41,122
Natural gas liquids (bbls/day)	1,418	3,411	4,829	2,136	3,009	5,145
Natural gas (Mcf/day)	79,878	218,625	298,503	144,788	222,183	366,971
Total average daily production (BOE/day)	28,228	65,431	93,659	41,730	65,699	107,429
Pricing[2]						
Crude oil (per bbl)	$ 43.27	$ 48.18	$ 46.48	$ 55.86	$ 59.71	$ 58.26
Natural gas liquids (per bbl)	25.14	11.74	15.67	33.58	11.87	20.88
Natural gas (per Mcf)	1.41	1.52	1.49	2.68	1.70	2.09
Capital Expenditures						
Capital spending	$ 7.2	$ 40.9	$ 48.1	$ 24.6	$ 123.4	$ 148.0
Acquisitions	1.0	(0.7)	0.3	0.8	(1.8)	(1.0)
Divestments	(91.1)	(1.6)	(92.7)	(187.1)	(0.7)	(187.8)
Netback[3] **Before Hedging**						
Oil and natural gas sales	$ 66.6	$ 146.1	$ 212.7	$ 120.7	$ 177.7	$ 298.4
Royalties	(9.7)	(28.7)	(38.4)	(11.7)	(35.0)	(46.7)
Production taxes	(0.1)	(8.5)	(8.6)	(0.9)	(13.3)	(14.2)
Cash operating expenses	(31.4)	(30.0)	(61.4)	(49.3)	(30.0)	(79.3)
Transportation costs	(3.9)	(20.6)	(24.5)	(5.8)	(22.2)	(28.0)
Netback before hedging	$ 21.5	$ 58.3	$ 79.8	$ 53.0	$ 77.2	$ 130.2
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 21.9	$ –	$ 21.9	$ 19.8	$ –	$ 19.8
General and administrative expense[4]	14.7	4.5	19.2	19.2	5.1	24.3
Current income tax expense/(recovery)	(0.4)	0.2	(0.2)	(0.4)	0.3	(0.1)

($ millions, except per unit amounts)	Six months ended June 30, 2016 Canada	U.S.	Total	Six months ended June 30, 2015 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	13,841	25,453	39,294	16,213	24,030	40,243
Natural gas liquids (bbls/day)	1,612	3,549	5,161	2,247	2,197	4,444
Natural gas (Mcf/day)	89,708	218,119	307,827	140,129	216,707	356,836
Total average daily production (BOE/day)	30,404	65,355	95,759	41,816	62,345	104,160
Pricing[2]						
Crude oil (per bbl)	$ 34.70	$ 41.33	$ 39.00	$ 48.37	$ 53.56	$ 51.35
Natural gas liquids (per bbl)	25.05	8.07	13.37	31.26	11.62	21.55
Natural gas (per Mcf)	1.74	1.59	1.64	2.90	1.95	2.32
Capital Expenditures						
Capital spending	$ 26.3	$ 65.1	$ 91.4	$ 101.5	$ 213.5	$ 315.0
Acquisitions	2.0	1.9	3.9	2.0	(3.2)	(1.2)
Divestments	(279.4)	(1.1)	(280.5)	(188.0)	(3.5)	(191.5)
Netback[3] **Before Hedging**						
Oil and natural gas sales	$ 123.3	$ 259.9	$ 383.2	$ 228.6	$ 313.9	$ 542.5
Royalties	(15.1)	(51.1)	(66.2)	(24.0)	(61.8)	(85.8)
Production taxes	(0.9)	(15.1)	(16.0)	(2.7)	(22.3)	(25.0)
Cash operating expenses	(74.9)	(58.8)	(133.7)	(106.4)	(59.8)	(166.2)
Transportation costs	(7.5)	(42.7)	(50.2)	(12.0)	(42.5)	(54.5)
Netback before hedging	$ 24.9	$ 92.2	$ 117.1	$ 83.5	$ 127.5	$ 211.0
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 8.4	$ –	$ 8.4	$ (30.6)	$ –	$ (30.6)
General and administrative expense[4]	33.1	8.6	41.7	42.7	13.6	56.3
Current income tax expense/(recovery)	(0.7)	0.3	(0.4)	(0.4)	0.4	–

(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 share-based compensation.

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	Diluted
2016				
Second Quarter	$ 174.3	$ (168.5)	$ (0.77)	$ (0.77)
First Quarter	142.7	(173.7)	(0.84)	(0.84)
Total 2016	$ 317.0	$ (342.2)	$ (1.61)	$ (1.61)
2015				
Fourth Quarter	$ 199.4	$ (625.0)	$ (3.03)	$ (3.03)
Third Quarter	228.3	(292.7)	(1.42)	(1.42)
Second Quarter	251.7	(312.5)	(1.52)	(1.52)
First Quarter	205.0	(293.2)	(1.42)	(1.42)
Total 2015	$ 884.4	$ (1,523.4)	$ (7.39)	$ (7.39)
2014				
Fourth Quarter	$ 325.3	$ 151.7	$ 0.74	$ 0.73
Third Quarter	378.3	67.4	0.33	0.32
Second Quarter	414.9	40.0	0.20	0.19
First Quarter	407.7	40.0	0.20	0.19
Total 2014	$ 1,526.2	$ 299.1	$ 1.46	$ 1.44

Oil and gas sales, net of royalties, increased in the second quarter compared to the first quarter of 2016 due to higher realized crude oil prices partially offset by lower natural gas prices and lower oil and gas production volumes. Oil and gas sales, net of royalties, increased during the first half of 2014, then decreased throughout 2015 and 2016 as commodity prices declined. During 2015, the impact of weak commodity prices was somewhat offset by increasing production. Net losses reported in 2015 and 2016 were primarily due to non-cash asset impairments and valuation allowances on our deferred tax asset related to the decrease in the trailing twelve month average commodity prices, along with reduced revenues.

U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2016, we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2016 UPDATED GUIDANCE

We have revised our full year 2016 guidance to reflect a modest increase in capital spend to support 2017 growth, stronger natural gas production from the Marcellus, a lower expected overall royalty expense and reduced operating and G&A expenses. All other guidance has been maintained and is summarized below. This guidance includes the second quarter sale of non-core natural gas properties located in northwest Alberta, but does not include any additional acquisitions or divestments.

Summary of 2016 Expectations	Target
Capital spending	$215 million (from $200 million)
Average annual production	92,000 – 94,000 BOE/day (from 90,000 – 94,000 BOE/day)
Crude oil and natural gas liquids volumes	43,000 – 45,000 bbls/day
Average royalty and production tax rate (% of oil and natural gas sales)	22% (from 23%)
Operating expenses	$7.90/BOE (from $8.50/BOE)
Transportation costs	$3.10/BOE
Cash G&A expenses	$1.95/BOE (from $2.00/BOE)

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. Netback is calculated as oil and natural gas sales less royalties, production taxes, cash operating expenses and transportation costs.

Calculation of Netback	Three months ended June 30,		Six months ended June 30,	
($ millions)	2016	2015	2016	2015
Oil and natural gas sales	$ 212.7	$ 298.4	$ 383.2	$ 542.5
Less:				
Royalties	(38.4)	(46.7)	(66.2)	(85.8)
Production taxes	(8.6)	(14.2)	(16.0)	(25.0)
Cash operating expenses[1]	(61.4)	(79.3)	(133.7)	(166.2)
Transportation costs	(24.5)	(28.0)	(50.2)	(54.5)
Netback before hedging	$ 79.8	$ 130.2	$ 117.1	$ 211.0
Cash gains/(losses) on derivative instruments	21.6	73.1	61.2	159.9
Netback after hedging	$ 101.4	$ 203.3	$ 178.3	$ 370.9

(1) Total operating expenses adjusted to exclude non-cash gains on fixed price electricity swaps of $0.9 million and $0.6 million in the three and six months ended June 30, 2016 and $2.6 million and $1.7 million in the three and six months ended June 30, 2015.

"Funds Flow" is used by Enerplus and is useful to investors and securities analysts in analyzing operating performance, leverage and liquidity. 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 Funds Flow ($ millions)	**Three months ended June 30,**		**Six months ended June 30,**	
	2016	**2015**	**2016**	**2015**
Cash flow from operating activities	$ 61.9	$ 135.0	$ 131.6	$ 266.2
Asset retirement obligation expenditures	0.7	2.6	3.2	6.5
Changes in non-cash operating working capital	13.4	22.8	(17.0)	(3.1)
Funds flow	$ 76.0	$ 160.4	$ 117.8	$ 269.6

"**Debt to Funds Flow Ratio**" is used by Enerplus and is useful to investors and securities analysts in analyzing leverage and liquidity. The debt to funds flow ratio is calculated as total debt net of cash divided by a trailing twelve months of funds flow. This measure is not equivalent to debt to earnings before interest, taxes, depreciation, amortization 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 funds flow.

Calculation of Adjusted Payout Ratio ($ millions)	**Three months ended June 30,**		**Six months ended June 30,**	
	2016	**2015**	**2016**	**2015**
Dividends	$ 6.5	$ 30.9	$ 21.0	$ 78.3
Capital and office expenditures	48.2	149.4	91.5	317.3
Sub-total	$ 54.7	$ 180.3	$ 112.5	$ 395.6
Funds flow	$ 76.0	$ 160.4	$ 117.8	$ 269.6
Adjusted payout ratio (%)	72%	112%	96%	147%

In addition, the Company uses certain financial measures within the "Liquidity and Capital Resources" section 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 "senior debt to adjusted EBITDA", "total debt to adjusted EBITDA", "total debt to capitalization", "senior debt to consolidated present value of total proven 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.

Reconciliation of Net Income to Adjusted EBITDA[(1)] ($ millions)	**June 30, 2016**
Net income/(loss)	$ (1,259.9)
Add:	
Interest	59.6
Current and deferred tax expense/(recovery)	502.0
DD&A and asset impairment	1,193.4
Other non-cash charges[(2)]	129.7
Sub-total	$ 624.8
Adjustment for material acquisitions and divestments[(3)]	(21.6)
Adjusted EBITDA	$ 603.2

(1) Adjusted EBITDA is calculated based on the trailing four quarters. Balances above at June 30, 2016 include the six months ended June 30, 2016 and the third and fourth quarters of 2015.
(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 disposition had been made at the beginning of the period.

INTERNAL CONTROLS AND PROCEDURES

Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures and internal control 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 Issuer's Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at June 30, 2016, 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 April 1, 2016 and ended June 30, 2016 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.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This MD&A contains certain forward-looking information and forward-looking statements within the meaning of applicable securities laws ("forward-looking information"). The use of any of the words "expect", "anticipate", "continue", "estimate", "guidance", "objective", "ongoing", "may", "will", "project", "should", "believe", "plans", "intends", "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 2016 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 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 programs in 2016 and 2017; expectations regarding our realized oil and natural gas prices; future royalty rates on our production and future production taxes; anticipated cash and non-cash G&A, share-based compensation and financing expenses; operating and transportation costs; capital spending levels in 2016 and its impact on our production level and land holdings; potential future asset and goodwill impairments, as well as the 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 cash taxes; our deferred income taxes; future debt and working capital levels and debt to 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 divestments, expected timing thereof, production and reductions in asset retirement obligations associated therewith and use of proceeds therefrom; expected gains for accounting purposes in respect to our repurchase of senior notes and our asset divestments; anticipated amount of interest expense savings in respect to our repurchase of senior notes; 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, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; that lack of adequate infrastructure will not result in curtailment of production and/or reduced realized prices; current commodity price, differentials and cost assumptions; the general continuance of current or, where applicable, assumed industry conditions; the continuation of assumed tax, royalty and regulatory regimes; the accuracy of the estimates of our reserve and contingent resource volumes; the continued availability of adequate debt and/or equity financing and funds flow to fund our capital, operating and working capital requirements, and dividend payments as needed; the continued availability and sufficiency of our 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 2016 guidance contained in this MD&A is based on the following: a WTI price of US$42.61/bbl, a NYMEX price of US$2.46/Mcf, an AECO price of $2.00/GJ and a USD/CDN exchange rate of 1.32. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information included in this 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 further decline of commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; curtailment of our production due to low realized prices or lack of adequate infrastructure; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inability to comply with debt covenants under our bank credit facility and outstanding senior notes; inaccurate estimation of our oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in the annual MD&A and in our other public filings).*

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.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	June 30, 2016	December 31, 2015
Assets			
Current Assets			
Cash		$ 49,172	$ 7,498
Accounts receivable	3	102,990	132,156
Deferred financial assets	15	14,228	71,438
Other current assets		9,297	9,953
		175,687	221,045
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	780,053	1,166,587
Other capital assets, net	4	14,996	19,686
Property, plant and equipment		795,049	1,186,273
Goodwill		645,420	657,831
Deferred income tax asset	13	186,667	516,085
Total Assets		$ 1,802,823	$ 2,581,234
Liabilities			
Current liabilities			
Accounts payable	6	$ 169,754	$ 239,950
Dividends payable		2,405	6,196
Current portion of long-term debt	7	28,620	–
Deferred financial liabilities	15	9,610	4,100
		210,389	250,246
Deferred financial liabilities	15	7,868	3,193
Long-term debt	7	694,699	1,223,682
Asset retirement obligation	8	188,207	206,359
		890,774	1,433,234
Total Liabilities		1,101,163	1,683,480
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: June 30, 2016 – 240 million shares December 31, 2015 – 206 million shares	14	3,365,962	3,133,524
Paid-in capital		55,589	56,176
Accumulated deficit		(3,057,849)	(2,694,618)
Accumulated other comprehensive income/(loss)		337,958	402,672
		701,660	897,754
Total Liabilities & Equity		$ 1,802,823	$ 2,581,234
Contingencies	16		

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

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

(CDN$ thousands) unaudited	Note	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Revenues					
Oil and natural gas sales, net of royalties	9	$ 174,330	$ 251,730	$ 316,991	$ 456,690
Commodity derivative instruments gain/(loss)	15	(21,907)	(19,751)	(8,443)	30,647
		152,423	231,979	308,548	487,337
Expenses					
Operating		60,540	76,744	133,130	164,471
Transportation		24,495	28,018	50,213	54,501
Production taxes		8,541	14,220	15,977	25,033
General and administrative	10	19,244	24,262	41,697	56,342
Depletion, depreciation and accretion		82,322	137,403	173,483	269,753
Asset impairment	5	148,679	497,247	194,856	764,858
Interest	11	10,634	16,121	25,350	33,154
Foreign exchange (gain)/loss	12	383	(27,656)	(54,025)	76,546
Gain on divestment of assets	4	(74,700)	–	(219,800)	–
Gain on prepayment of senior notes	7	(12,152)	–	(19,270)	–
Other expense/(income)		(82)	(85)	(242)	8,527
		267,904	766,274	341,369	1,453,185
Income/(Loss) before taxes		(115,481)	(534,295)	(32,821)	(965,848)
Current income tax expense/(recovery)	13	(227)	(102)	(386)	(39)
Deferred income tax expense/(recovery)	13	53,300	(221,649)	309,785	(360,059)
Net Income/(Loss)		$ (168,554)	$ (312,544)	$ (342,220)	$ (605,750)
Other Comprehensive Income/(Loss)					
Change in cumulative translation adjustment		1,654	(30,490)	(64,714)	146,269
Other Comprehensive Income/(Loss)		1,654	(30,490)	(64,714)	146,269
Total Comprehensive Income/(Loss)		$ (166,900)	$ (343,034)	$ (406,934)	$ (459,481)
Net income/(Loss) per share					
Basic	14	$ (0.77)	$ (1.52)	$ (1.61)	$ (2.94)
Diluted	14	$ (0.77)	$ (1.52)	$ (1.61)	$ (2.94)

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

Condensed Consolidated Statements of Changes in Shareholders' Equity

Six months ended June 30 (CDN$ thousands) unaudited	2016	2015
Share Capital		
Balance, beginning of year	$ 3,133,524	$ 3,120,002
Issue of shares (net of issue costs)	223,031	–
Stock Option Plan – cash	–	3,205
Share-based compensation – settled	9,407	3,094
Stock Option Plan – exercised	–	267
Balance, end of period	$ 3,365,962	$ 3,126,568
Paid-in Capital		
Balance, beginning of year	$ 56,176	$ 46,906
Share-based compensation – settled	(9,407)	(3,094)
Stock Option Plan – exercised	–	(267)
Share-based compensation – non-cash	8,820	9,561
Balance, end of period	$ 55,589	$ 53,106
Accumulated Deficit		
Balance, beginning of year	$ (2,694,618)	$ (1,039,260)
Net income/(loss)	(342,220)	(605,750)
Dividends	(21,011)	(78,294)
Balance, end of period	$ (3,057,849)	$ (1,723,304)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of year	$ 402,672	$ 95,478
Change in cumulative translation adjustment	(64,714)	146,269
Balance, end of period	$ 337,958	$ 241,747
Total Shareholders' Equity	$ 701,660	$ 1,698,117

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

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Operating Activities					
Net income/(loss)		$ (168,554)	$ (312,544)	$ (342,220)	$ (605,750)
Non-cash items add/(deduct):					
Depletion, depreciation and accretion		82,322	137,403	173,483	269,753
Asset impairment	5	148,679	497,247	194,856	764,858
Changes in fair value of derivative instruments	15	41,060	73,738	67,395	161,237
Deferred income tax expense/(recovery)	13	53,300	(221,649)	309,785	(360,059)
Foreign exchange (gain)/loss on debt and working capital	12	131	(18,590)	(56,027)	69,424
Share-based compensation	14	5,391	4,591	8,820	9,561
Amortization of debt issue costs	11	570	240	752	480
Gain on divestment of assets	4	(74,700)	–	(219,800)	–
Gain on prepayment of senior notes	7	(12,152)	–	(19,270)	–
Derivative settlement of foreign exchange swaps		–	–	–	(39,904)
Asset retirement obligation expenditures	8	(750)	(2,569)	(3,204)	(6,459)
Changes in non-cash operating working capital	17	(13,410)	(22,771)	17,064	3,051
Cash flow from/(used in) operating activities		61,887	135,096	131,634	266,192
Financing Activities					
Proceeds from the issuance of shares	14	220,410	634	220,410	3,205
Cash dividends	14	(6,547)	(30,935)	(21,011)	(78,294)
Increase/(decrease) in bank credit facility		(150,073)	(45,386)	(79,223)	434
Proceeds/(repayment) of senior notes	7	(109,371)	(88,897)	(335,400)	(88,897)
Derivative settlement of foreign exchange swaps		–	–	–	39,904
Changes in non-cash financing working capital		334	(15)	(3,791)	(8,222)
Cash flow from/(used in) financing activities		(45,247)	(164,599)	(219,015)	(131,870)
Investing Activities					
Capital and office expenditures		(48,206)	(149,439)	(91,498)	(317,327)
Property and land acquisitions		(343)	1,011	(3,897)	1,247
Property divestments	4	92,735	187,801	280,503	191,513
Changes in non-cash investing working capital		(11,909)	(12,148)	(54,035)	(11,217)
Cash flow from/(used in) investing activities		32,277	27,225	131,073	(135,784)
Effect of exchange rate changes on cash		(1,026)	677	(2,018)	428
Change in cash		47,891	(1,601)	41,674	(1,034)
Cash, beginning of period		1,281	2,603	7,498	2,036
Cash, end of period		$ 49,172	$ 1,002	$ 49,172	$ 1,002

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

Notes to Condensed Consolidated Financial Statements

(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim 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. The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on August 4, 2016.

2) BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under accounting principles generally accepted in the United States of America ("U.S. GAAP") for the three and six months ended June 30, 2016 and the 2015 comparative periods. Certain information and notes normally included with the annual audited Consolidated Financial Statements have been condensed or have been disclosed on an annual basis only. Accordingly, these interim Consolidated Financial Statements should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2015. There are no differences in the use of estimates or judgments between these interim Consolidated Financial Statements and the audited Consolidated Financial Statements and notes thereto for the year ended December 31, 2015.

These unaudited interim Consolidated Financial Statements reflect, in the opinion of Management, all normal and recurring adjustments necessary to present fairly the financial position and results of the Company as at and for the periods presented.

3) ACCOUNTS RECEIVABLE

($ thousands)	June 30, 2016	December 31, 2015
Accrued receivables	$ 85,367	$ 91,378
Accounts receivable – trade	19,523	22,615
Current income tax receivable	1,488	21,410
Allowance for doubtful accounts	(3,388)	(3,247)
Total accounts receivable	$ 102,990	$ 132,156

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

As at June 30, 2016 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,204,112	$ (12,424,059)	$ 780,053
Other capital assets	104,155	(89,159)	14,996
Total PP&E	$ 13,308,267	$ (12,513,218)	$ 795,049

As at December 31, 2015 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,541,670	$ (12,375,083)	$ 1,166,587
Other capital assets	105,124	(85,438)	19,686
Total PP&E	$ 13,646,794	$ (12,460,521)	$ 1,186,273

During the three and six months ended June 30, 2016, Enerplus disposed of certain Canadian properties for proceeds of $92.7 million and $280.5 million, respectively, which resulted in gains on asset divestments of $74.7 million and $219.8 million, respectively (2015 – nil and nil, respectively).

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.

5) ASSET IMPAIRMENT

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2016	2015	2016	2015
Oil and natural gas properties:				
Canada cost centre	$ 34,200	$ 28,100	$ 34,200	$ 28,100
U.S. cost centre	114,479	469,147	160,656	736,758
Impairment expense	$ 148,679	$ 497,247	$ 194,856	$ 764,858

The impairments for the three and six months ended June 30, 2016 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 tests from June 30, 2015 through June 30, 2016:

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
Q2 2016	$ 43.12	1.32	$ 53.16	$ 2.25	$ 2.14
Q1 2016	46.26	1.32	56.97	2.41	2.47
Q4 2015	50.28	1.27	59.38	2.58	2.69
Q3 2015	59.21	1.22	66.51	3.08	3.00
Q2 2015	71.75	1.16	75.83	3.42	3.33

6) ACCOUNTS PAYABLE

($ thousands)	June 30, 2016	December 31, 2015
Accrued payables	$ 92,806	$ 167,253
Accounts payable – trade	76,948	72,697
Total accounts payable	$ 169,754	$ 239,950

7) DEBT

($ thousands)	June 30, 2016	December 31, 2015
Current:		
Senior notes	$ 28,620	$ –
	28,620	–
Long-term:		
Bank credit facility	$ –	$ 86,543
Senior notes	694,699	1,137,139
	694,699	1,223,682
Total debt	$ 723,319	$ 1,223,682

For the three and six months ended June 30, 2016, Enerplus has repurchased US$95 million and US$267 million, respectively, in outstanding senior notes at a discount, resulting in gains of $12.2 million and $19.3 million, respectively. These repurchases have resulted in total payments of $109.4 million and $335.4 million for the three and six months ended June 30, 2016.

The terms and rates of the Company's outstanding senior notes are provided 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	$ 136,534
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	26,018
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$298,000	387,668
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$110,000	143,099
					Total carrying value	$ 723,319

8) ASSET RETIREMENT OBLIGATION

Enerplus has estimated the present value of its asset retirement obligation to be $188.2 million at June 30, 2016 compared to $206.4 million at December 31, 2015 based on a total undiscounted liability of $472.4 million and $556.4 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.90% (December 31, 2015 – 5.91%).

($ thousands)	Six months ended June 30, 2016	Year ended December 31, 2015
Balance, beginning of year	$ 206,359	$ 288,692
Change in estimates	1,819	(35,386)
Property acquisitions and development activity	240	761
Divestments	(22,648)	(48,748)
Settlements	(3,204)	(14,935)
Accretion expense	5,641	15,975
Balance, end of period	$ 188,207	$ 206,359

9) OIL AND NATURAL GAS SALES

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2016	2015	2016	2015
Oil and natural gas sales	$ 212,741	$ 298,433	$ 383,164	$ 542,510
Royalties(1)	(38,411)	(46,703)	(66,173)	(85,820)
Oil and natural gas sales, net of royalties	$ 174,330	$ 251,730	$ 316,991	$ 456,690

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

10) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2016	2015	2016	2015
General and administrative expense	$ 14,600	$ 19,872	$ 33,026	$ 41,307
Share-based compensation expense	4,644	4,390	8,671	15,035
General and administrative expense	$ 19,244	$ 24,262	$ 41,697	$ 56,342

11) INTEREST EXPENSE

($ thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Realized:				
Interest on bank debt and senior notes	$ 10,064	$ 15,881	$ 24,598	$ 32,674
Unrealized:				
Amortization of debt issue costs	570	240	752	480
Interest expense	$ 10,634	$ 16,121	$ 25,350	$ 33,154

12) FOREIGN EXCHANGE

($ thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Realized:				
Foreign exchange (gain)/loss	$ 252	$ 8,402	$ 2,002	$ (27,172)
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	131	(18,590)	(56,027)	69,424
Foreign exchange derivatives (gain)/loss	–	(17,468)	–	34,294
Foreign exchange (gain)/loss	$ 383	$ (27,656)	$ (54,025)	$ 76,546

13) INCOME TAXES

Enerplus' provision for income tax is as follows:

($ thousands)	Three months ended June 30, 2016	Three months ended June 30, 2015	Six months ended June 30, 2016	Six months ended June 30, 2015
Current tax expense/(recovery)				
Canada	$ (366)	$ (400)	$ (669)	$ (400)
United States	139	298	283	361
Current tax expense/(recovery)	(227)	(102)	(386)	(39)
Deferred tax expense/(recovery)				
Canada	$ 21,069	$ (27,676)	$ 33,915	$ (36,939)
United States	32,231	(193,973)	275,870	(323,120)
Deferred tax expense/(recovery)	53,300	(221,649)	309,785	(360,059)
Income tax expense/(recovery)	$ 53,073	$ (221,751)	$ 309,399	$ (360,098)

The difference between expected income taxes based on the statutory income tax rate and the effective income tax rate for the current and prior period is impacted by the following: expected annual earnings, recognition of valuation allowance, foreign rate differentials for foreign operations, statutory and other rate differentials, the reversal or recognition of previously recognized or unrecognized deferred tax assets, non-taxable portions of capital gains and losses, and non-deductible share-based compensation. Enerplus recorded valuation allowances of $105.0 million and $363.5 million as at the three and six month periods ended June 30, 2016, respectively (2015 – nil and nil, respectively).

14) SHAREHOLDERS' EQUITY

a) Share Capital

	Six months ended June 30, 2016		Year ended December 31, 2015	
Authorized unlimited number of common shares Issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	206,539	$ 3,133,524	205,732	$ 3,120,002
Issued for cash:				
Stock Option Plan	–	–	234	3,205
Issue of shares	33,350	230,115	–	–
Share issue costs (net of tax of $2,620)	–	(7,084)	–	–
Non-cash:				
Share-based compensation – settled	594	9,407	573	10,050
Stock Option Plan – exercised	–	–	–	267
Balance, end of period	240,483	$ 3,365,962	206,539	$ 3,133,524

Dividends declared to shareholders for the three and six months ended June 30, 2016 were $6.5 million and $21.0 million, respectively (2015 – $30.9 million and $78.3 million, respectively).

On May 31, 2016, Enerplus issued 33,350,000 common shares at a price of $6.90 per share for gross proceeds of $230,115,000 ($220,410,400 net of issue costs).

At the Company's Annual General Meeting on May 6, 2016, the Shareholders of the Company approved a reduction in Enerplus' legal stated capital to $1 per share to be reflected in the contributed surplus account of the Company. This transaction does not result in an adjustment to the financial statements under U.S. GAAP.

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):

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2016**	**2015**	**2016**	**2015**
Cash:				
Long-term incentive plans expense	$ 773	$ (1,233)	$ 1,506	$ 6,041
Non-cash:				
Long-term incentive plans and stock option expense	5,391	4,591	8,820	9,561
Equity swap (gain)/loss	(1,520)	1,032	(1,655)	(567)
Share-based compensation expense	$ 4,644	$ 4,390	$ 8,671	$ 15,035

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

In 2014, the Performance Share Unit ("PSU") and Restricted Share Unit ("RSU") plans were amended such that grants under the plans are settled through the issuance of treasury shares. The amendment was effective beginning with our grant in March of 2014 and any prior grants were settled in cash. The final cash-settled PSU and RSU grants were settled in December, 2015 and March, 2016, respectively. The Company's Director Share Units ("DSU") continue to be granted as cash-settled awards.

The following table summarizes the PSU, RSU and DSU activity for the six months ended June 30, 2016:

For the six months ended June 30, 2016 (thousands of units)	**Cash-settled LTI plans**		**Equity-settled LTI plans**		
	RSU	**DSU**	**PSU**	**RSU**	**Total**
Balance, beginning of year	92	166	1,222	1,627	3,107
Granted	–	134	1,417	1,987	3,538
Vested	(89)	–	(9)	(594)	(692)
Forfeited	(3)	–	(88)	(202)	(293)
Balance, end of period	–	300	2,542	2,818	5,660

Cash-settled LTI Plans

For the three and six months ended June 30, 2016, the Company recorded cash share-based compensation of $0.8 million and $1.5 million, respectively (June 30, 2015 – recovery of $1.2 million and expense of $6.0 million). For the three and six months ended June 30, 2016 the Company made cash payments of nil and $2.7 million, respectively, related to its cash-settled plans (June 30, 2015 – nil and $5.6 million).

As of June 30, 2016, a liability of $2.6 million (December 31, 2015 – $2.3 million) with respect to the DSU plan has been recorded to Accounts Payable on the Consolidated Balance Sheets.

Equity-settled LTI Plans

For the three and six months ended June 30, 2016 the Company recorded non-cash share-based compensation expense of $5.4 million and $8.8 million, respectively (2015 – $4.6 million and $9.6 million, respectively).

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 June 30, 2016 ($ thousands, except for years)	**PSU(1)**	**RSU**	**Total**
Cumulative recognized share-based compensation expense	$ 9,403	$ 11,219	$ 20,622
Unrecognized share-based compensation expense	8,861	9,241	18,102
Fair value	$ 18,264	$ 20,460	$ 38,724
Weighted-average remaining contractual term (years)	1.9	1.5	

(1) Includes estimated performance multipliers.

ii) Stock Option Plan

The Company did not grant any stock options for the three and six months ended June 30, 2016. At June 30, 2016 all stock options are fully vested and any related non-cash share-based compensation expense has been fully recognized.

The following table summarizes the stock option plan activity for the period ended June 30, 2016:

Period ended June 30, 2016	**Number of Options** (thousands)	**Weighted Average Exercise Price**
Options outstanding, beginning of year	7,580	$ 18.49
Forfeited	(1,070)	18.76
Options outstanding, end of period	6,510	$ 18.45
Options exercisable, end of period	6,510	$ 18.45

At June 30, 2016, Enerplus had 6,510,000 options that were exercisable at a weighted average reduced exercise price of $18.45 with a weighted average remaining contractual term of 3.0 years, giving an aggregate intrinsic value of nil (2015 – nil). The intrinsic value of options exercised for both the three and six months ended June 30, 2016 was nil (June 30, 2015 – $0.1 million and $0.2 million, respectively).

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

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

	Three months ended June 30,		Six months ended June 30,	
(thousands, except per share amounts)	2016	2015	2016	2015
Net income/(loss)	$ (168,554)	$ (312,544)	$ (342,220)	$ (605,750)
Weighted average shares outstanding – Basic	218,128	206,208	212,420	206,028
Dilutive impact of share-based compensation[1]	–	–	–	–
Weighted average shares outstanding – Diluted	218,128	206,208	212,420	206,028
Net income/(loss) per share				
Basic	$ (0.77)	$ (1.52)	$ (1.61)	$ (2.94)
Diluted[1]	$ (0.77)	$ (1.52)	$ (1.61)	$ (2.94)

(1) For the three and six months ended June 30, 2016 the impact of share-based compensation was anti-dilutive as a conversion to shares would not increase the loss per share.

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At June 30, 2016 the carrying value of cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value due to the short-term maturity of the instruments.

At June 30, 2016 senior notes had a carrying value of $723.3 million and a fair value of $791.9 million (December 31, 2015 – $1,137.2 million and $1,220.8 million, respectively).

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

b) Derivative Financial Instruments

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

The following table summarizes the change in fair value for the three and six months ended June 30, 2016 and 2015:

	Three months ended June 30,		Six months ended June 30,		
Gain/(Loss) ($ thousands)	2016	2015	2016	2015	Income Statement Presentation
Foreign Exchange Derivatives	$ –	$ 17,468	$ –	$ (34,294)	Foreign exchange
Electricity Swaps	885	2,642	577	1,715	Operating expense
Equity Swaps	1,520	(1,032)	1,655	567	General and administrative expense
Commodity Derivative Instruments:					
Oil	(27,144)	(71,085)	(58,420)	(107,044)	Commodity derivative instruments
Gas	(16,321)	(21,731)	(11,207)	(22,181)	
Total	$ (41,060)	$ (73,738)	$ (67,395)	$ (161,237)	

The following table summarizes the income statement effects of Enerplus' commodity derivative instruments:

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2016	2015	2016	2015
Change in fair value gain/(loss)	$ (43,465)	$ (92,816)	$ (69,627)	$ (129,225)
Net realized cash gain/(loss)	21,558	73,065	61,184	159,872
Commodity derivative instruments gain/(loss)	$ (21,907)	$ (19,751)	$ (8,443)	$ 30,647

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

	June 30, 2016			December 31, 2015		
	Assets	Liabilities		Assets	Liabilities	
($ thousands)	Current	Current	Long-term	Current	Current	Long-term
Electricity Swaps	$ –	$ 1,199	$ –	$ –	$ 1,776	$ –
Equity Swaps	–	2,580	1,282	–	2,324	3,193
Commodity Derivative Instruments:						
Oil	14,228	–	5,251	67,397	–	–
Gas	–	5,831	1,335	4,041	–	–
Total	$ 14,228	$ 9,610	$ 7,868	$ 71,438	$ 4,100	$ 3,193

c) Risk Management

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 the Corporation's price risk management positions at July 22, 2016:

Crude Oil Instruments:

Instrument Type[(1)]	bbls/day	US$/bbl
Jul 1, 2016 – Dec 31, 2016		
WTI Purchased Put	12,000	57.82
WTI Sold Call	12,000	71.75
WTI Sold Put	12,000	45.09
WCS Differential Swap	3,000	(14.03)
MSW Differential Swap	1,000	(3.50)
Jan 1, 2017 – Dec 31, 2017		
WTI Purchased Put	12,000	50.00
WTI Sold Call	12,000	60.50
WTI Sold Put	12,000	38.59

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

Natural Gas Instruments:

Instrument Type[1]	MMcf/day	US$/Mcf
Jul 1, 2016 – Oct 31, 2016		
NYMEX Swap	50.0	2.53
NYMEX Purchased Put	25.0	3.00
NYMEX Sold Call	25.0	3.75
NYMEX Sold Put	25.0	2.50
Nov 1, 2016 – Dec 31, 2016		
NYMEX Swap	25.0	2.48
NYMEX Purchased Put	25.0	3.00
NYMEX Sold Call	25.0	3.75
NYMEX Sold Put	25.0	2.50
Jan 1, 2017 – Dec 31, 2017		
NYMEX Purchased Put	45.0	2.72
NYMEX Sold Call	45.0	3.37
NYMEX Sold Put	45.0	2.03

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

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Jul 1, 2016 – Dec 31, 2016		
AESO Power Swap[1]	15.0	46.60
Jan 1, 2017 – Dec 31, 2017		
AESO Power Swap[1]	6.0	44.38

(1) Alberta Electrical System Operator ("AESO") fixed pricing.

Physical Contracts:

Instrument Type	MMcf/day	US$/Mcf
Jul 1, 2016 – Oct 31, 2016 AECO-NYMEX Basis	21.4	(0.68)
Nov 1, 2016 – Oct 31, 2017 AECO-NYMEX Basis	80.0	(0.65)
Nov 1, 2017 – Oct 31, 2018 AECO-NYMEX Basis	80.0	(0.65)
Nov 1, 2018 – Oct 31, 2019 AECO-NYMEX Basis	80.0	(0.64)

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, and U.S. dollar denominated senior notes and working capital. Additionally, Enerplus' crude oil sales and a 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 June 30, 2016 Enerplus did not have any foreign exchange derivatives outstanding.

Interest Rate Risk:

As of June 30, 2016 all of Enerplus' debt was based on fixed interest rates, and Enerplus had no 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 14. Enerplus has entered into various equity swaps maturing between 2016 and 2018 and has effectively fixed the figure settlement cost on 470,000 shares at 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 June 30, 2016 approximately 50% of Enerplus' marketing receivables were with companies considered investment grade.

At June 30, 2016 approximately $2.1 million or 2% of Enerplus' total accounts receivable were aged over 120 days and considered past due. The majority of these accounts are due from various joint venture partners. Enerplus actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production, netting amounts of 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 uncollectable the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at June 30, 2016 was $3.4 million (December 31, 2015 – $3.2 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 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 June 30, 2016 Enerplus was in full compliance with all covenants under the bank credit facility and outstanding senior notes.

16) 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.

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes In Non-Cash Operating Working Capital

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2016	2015	2016	2015
Accounts receivable	$ 288	$ (5,371)	$ 29,640	$ 18,696
Other current assets	(3,426)	(10,079)	(96)	(14,877)
Accounts payable	(10,272)	(7,321)	(12,480)	(768)
	$ (13,410)	$ (22,771)	$ 17,064	$ 3,051

b) Other

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2016	2015	2016	2015
Income taxes paid/(received)	$ (17,194)	$ 148	$ (19,118)	$ (19,197)
Interest paid	17,832	25,936	27,638	32,418

BOARD OF DIRECTORS

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Corporate Director
Boerne, Texas

David H. Barr(9)(12)
Corporate Director
The Woodlands, Texas

Michael R. Culbert(3)(5)(9)
President & CEO
Progress Energy Canada Ltd.
Calgary, Alberta

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

Hilary A. Foulkes(5)(7)(9)(11)
Corporate Director
Calgary, Alberta

Robert B. Hodgins(3)(6)
Corporate Director
Calgary, Alberta

Susan M. MacKenzie(7)(10)(11)
Corporate Director
Calgary, Alberta

Glen D. Roane(4)(5)
Corporate Director
Canmore, Alberta

Sheldon B. Steeves(5)(8)
Corporate Director
Calgary, Alberta

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

Ray J. Daniels
Senior Vice President, Operations

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, U.S. Operations

Lisa M. Ower
Vice President, People & Culture

Shaina B. Morihira
Corporate Controller, Finance

(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

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

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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
Bcfe	billion cubic feet equivalent
BOE	barrels of oil equivalent
Brent	crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.
LTI	long-term incentive
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf	million cubic feet
MSW	mixed sweet blend
MWh	megawatt hour(s) of electricity
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
OCI	other comprehensive income
SBC	share based compensation
SDP	stock dividend program
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

Why invest in Enerplus?

Enerplus Corporation is a responsible developer of high quality crude oil and natural gas assets in Canada and the United States, focused on providing both growth and income to its shareholders.

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