Q3 2015

enerPLUS

THIRD QUARTER REPORT
NINE MONTHS ENDED SEPTEMBER 30, 2015

SELECTED FINANCIAL RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Financial (000's)				
Funds Flow[4]	$ 120,845	$ 212,779	$ 390,427	$ 646,502
Cash and Stock Dividends	30,944	55,438	109,238	165,587
Net Income/(Loss)	(292,666)	67,430	(898,416)	147,424
Debt Outstanding – net of cash	1,226,552	1,091,110	1,226,552	1,091,110
Capital Spending	88,923	207,838	403,913	630,027
Property and Land Acquisitions	2,005	3,986	758	17,186
Property Divestments	11,865	68,931	203,378	185,631
Debt to Funds Flow Ratio[4]	2.0x	1.3x	2.0x	1.3x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 0.58	$ 1.04	$ 1.89	$ 3.17
Net Income/(Loss)	(1.42)	0.33	(4.36)	0.72
Weighted Average Number of Shares Outstanding (000's)	206,243	205,164	206,100	204,174
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 27.04	$ 47.67	$ 28.17	$ 52.13
Royalties and Production Taxes	(6.01)	(10.36)	(5.93)	(11.31)
Commodity Derivative Instruments	5.31	(0.26)	7.36	(1.52)
Cash Operating Expenses	(8.69)	(9.29)	(8.77)	(9.14)
Transportation Costs	(3.03)	(2.92)	(2.94)	(2.61)
General and Administrative	(2.24)	(1.97)	(2.21)	(2.08)
Cash Share-Based Compensation	0.35	0.54	(0.08)	(0.44)
Interest, Foreign Exchange and Other Expenses	(2.47)	(1.18)	(2.72)	(1.48)
Taxes	1.59	–	0.56	(0.40)
Funds Flow	$ 11.85	$ 22.23	$ 13.44	$ 23.15

SELECTED OPERATING RESULTS	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Average Daily Production[2]				
Crude Oil (bbls/day)	44,888	40,332	41,809	39,328
Natural Gas Liquids (bbls/day)	5,061	3,869	4,652	3,591
Natural Gas (Mcf/day)	365,071	359,007	359,611	356,288
Total (BOE/day)	110,794	104,035	106,396	102,300
% Crude Oil and Natural Gas Liquids	45%	42%	44%	42%
Average Selling Price[2][3]				
Crude Oil (per bbl)	$ 48.22	$ 88.28	$ 50.21	$ 92.55
Natural Gas Liquids (per bbl)	13.51	46.76	18.60	54.79
Natural Gas (per Mcf)	2.08	3.36	2.24	4.18
Net Wells Drilled	8	19	44	63

(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 September 30, 2015	2014	Nine months ended September 30, 2015	2014
WTI Crude Oil (US$/bbl)	$ 46.43	$ 97.17	$ 51.00	$ 99.61
AECO – monthly index (CDN$/Mcf)	2.80	4.22	2.80	4.55
AECO – daily index (CDN$/Mcf)	2.90	4.02	2.77	4.81
NYMEX – last day (US$/Mcf)	2.77	4.06	2.80	4.55
US/CDN exchange rate	1.31	1.09	1.26	1.09

Share Trading Summary For the three months ended September 30, 2015	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 10.93	$ 8.80
Low	$ 6.04	$ 4.54
Close	$ 6.50	$ 4.86

* TSX and other Canadian trading data combined.

** NYSE and other U.S. trading data combined.

2015 Dividends per Share Payment Month	CDN$	US$(1)
First Quarter Total	$ 0.27	$ 0.22
Second Quarter Total	$ 0.15	$ 0.12
July	$ 0.05	$ 0.04
August	0.05	0.04
September	0.05	0.04
Third Quarter Total	$ 0.15	$ 0.12
Total Year-to-Date	$ 0.57	$ 0.46

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

PRESIDENT'S MESSAGE

Enerplus delivered another quarter of strong operational performance. With the continued improvement in our capital efficiencies and the lowering of our cost structure, we are increasing our 2015 production guidance, while reducing our guidance for capital spending, operating and G&A costs. As we look ahead into 2016, our focus is on sustainability. Our 2016 capital budget is down 30% from 2015, and we expect to operate near or within funds flow. To further enhance the company's financial strength and sustainability in an extended low commodity price environment, we are reducing our monthly dividend to $0.03 per share from $0.05 per share effective with our December 2015 dividend payment. While the dividend remains an important part of our strategy, its reduction reflects the need to rebalance the dividend level in the context of lower commodity prices.

Production was up 3% quarter over quarter averaging 110,794 BOE per day. This growth was primarily driven by North Dakota oil production, which increased over 20% from the second quarter of 2015 as a result of continued strong well performance and higher activity levels in the second and third quarters. Natural gas production was broadly unchanged from the previous quarter at approximately 365 MMcf per day, with continued outperformance in the Marcellus offsetting a decrease in Canadian deep gas production resulting from scheduled turnarounds at major facilities. Overall, crude oil and natural gas liquids production increased to approximately 50,000 barrels per day during the quarter, up 8% over the previous quarter. Looking forward, we expect fourth quarter oil production to be lower than the third quarter as a result of both reduced on-stream activity in North Dakota and divestments.

Subsequent to the quarter, we entered into an agreement to sell a portion of our non-operated North Dakota properties for proceeds of $80 million. This accretive divestment allows us to increase our focus on our operated North Dakota acreage where we can better align our financial and operational objectives. The divestment includes less than 2% of our overall North Dakota acreage. Estimated 2016 production from the existing wells within these properties is 1,000 BOE per day. The transaction is expected to close in the fourth quarter. We also divested some minor non-core Canadian oil properties during the quarter, with associated production of 150 BOE per day, for proceeds of approximately $12 million.

As a result of the strong production performance year to date, we are increasing our 2015 annual average production guidance to 106,000 BOE per day (from 100,000 – 104,000 BOE per day), with approximately 46,000 barrels per day of crude oil and natural gas liquids (from 44,000 – 46,000 barrels per day). This increased guidance assumes the non-operated North Dakota divestment closes in the fourth quarter of 2015.

Funds flow was $121 million in the third quarter, down from $160 million in the previous quarter, primarily due to the decline in crude oil prices in the period.

Capital spending was $89 million in the third quarter, down from $148 million in the second quarter. Capital was focused on our crude oil projects, with over 90% of spending directed to North Dakota and our Canadian waterflood assets. Due to continued cost improvement, strong operational performance, and the deferral of spending into 2016, we have reduced our annual 2015 capital spending to $510 million, down from $540 million.

Operating costs during the quarter were $8.87 per BOE, below our annual guidance of $9.25 per BOE. As expected, we saw an increase in operating costs from the second quarter as a result of seasonal turnaround activity. Third quarter cash G&A costs were $2.24 per BOE, in line with our annual guidance, despite one-time severance charges related to staff reductions that were incurred in the quarter. As a result of the continued improvement in our cost structures and increased production guidance, we are decreasing our 2015 annual operating cost guidance to $9.00 per BOE and our cash G&A expense guidance to $2.20/BOE.

We incurred a non-cash asset impairment charge in the quarter of $321 million (before tax). Under U.S. GAAP we are required to use twelve month trailing average prices to determine impairment, and consequently the impairment reflects the low commodity prices in the fourth quarter of 2014 and the first three quarters of 2015.

We ended the third quarter with a debt to funds flow ratio of 2.0 times and senior debt to EBITDA ratio of 1.8 times. Subsequent to the quarter, we paid the final installment of US$10.8 million on our maturing US$54 million senior notes. We have no additional scheduled debt repayments until June of 2017.

At September 30, 2015 we were approximately 11% drawn on our covenant based $1.0 billion bank credit facility. Subsequent to the quarter, we completed a one year extension of our bank credit facility with our lending syndicate, which now matures in October 2018. After confirming with our syndicate banks that we could have maintained the facility at its current level, we chose to decrease the facility limit to $800 million as part of our ongoing cost savings initiatives. This decision balances the need for sufficient liquidity for the execution of our business plan against the associated costs of retaining a largely undrawn bank facility. We expect to realize savings of approximately $1 million as a result of the decreased facility size. At the end of 2015, we expect to be approximately 10% drawn on the resized credit facility.

Production and Capital Spending

	Three months ended September 30, 2015		Nine months ended September 30, 2015	
	Average Production Volumes	Capital Spending ($ millions)	Average Production Volumes	Capital Spending ($ millions)
Crude Oil & NGLs (bbls/day)				
Canada	16,209	23.9	17,702	91.9
United States	33,740	58.6	28,759	252.9
Total Crude Oil & NGLs (bbls/day)	**49,949**	**82.5**	**46,461**	**344.8**
Natural Gas (Mcf/day)				
Canada	131,644	3.1	137,270	30.6
United States	233,427	3.3	222,341	28.5
Total Natural Gas (Mcf/day)	**365,071**	**6.4**	**359,611**	**59.1**
Company Total (BOE/day)	**110,794**	**88.9**	**106,396**	**403.9**

Net Drilling Activity*** – for the three months ended September 30, 2015

	Wells Drilled	Wells Pending Completion/Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Crude Oil				
Canada	3.0	2.0	2.0	–
United States	3.8	3.8	6.5	–
Total Crude Oil	**6.8**	**5.8**	**8.5**	**–**
Natural Gas				
Canada	0.6	–	2.3	–
United States	0.7	0.7	0.5	–
Total Natural Gas	**1.3**	**0.7**	**2.8**	**–**
Company Total	**8.0**	**6.4**	**11.3**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment as at September 30, 2015.
** Total wells brought on-stream during the quarter regardless of when they were drilled.
*** Table may not add due to rounding.

Asset Activity

Production from North Dakota in the quarter was up over 20% from the previous quarter, averaging 32,600 BOE per day. We drilled 3.8 net wells in Fort Berthold with 6.5 net wells brought on-stream during the quarter for a total capital investment of $58 million. The growth in production is a result of continued strong well performance and an increase in on-stream activity during the second and third quarters. Our operated well completions activity was focused in the southeast area of our Fort Berthold acreage and included wells in both the Bakken and Three Forks formations. The wells were completed using a modified high volume completion design, and produced at an average initial 30 day production rate (IP30) of over 1,600 BOE per day, outperforming expectations. Well costs continue to trend down, with average well costs in the quarter, including facilities costs, of just under US$10 million. We continue to run a one-rig drilling program and, having deferred some completion activity into 2016, expect to have an inventory of approximately 10 drilled uncompleted wells at the end of 2015.

We continue to see reduced activity levels in the Marcellus. During the third quarter, our capital spending in the Marcellus was $3 million with 0.7 net wells drilled and 0.5 net wells brought on-stream. Despite the low capital investment, strong well performance led to a 5% production increase, to 210 MMcf per day, over the previous quarter.

In Canada, following the commercial success of the polymer pilot project at our Medicine Hat Glauc 'C' waterflood asset, we have sanctioned the installation of a second skid for our next polymer project. Construction of the project was completed in October on budget and on schedule. Polymer injection commenced in late October.

Crude Oil & Natural Gas Pricing

The West Texas Intermediate (WTI) benchmark price for crude oil fell by 20% versus the previous quarter to average US$46.43 per barrel during the third quarter. Although our U.S. Bakken crude oil differentials narrowed in the third quarter, the weakness in WTI prices resulted in a 17% reduction in the selling price for our crude oil compared to the previous quarter.

Natural gas prices at AECO and NYMEX were slightly stronger during the third quarter, both averaging 5% higher than the previous quarter. However, strong production levels and significant maintenance activities on the two major pipelines running through Northeast Pennsylvania contributed to the continued weakness in regional Marcellus pricing during the quarter, offsetting the strength in AECO and NYMEX on our realized natural gas price.

Marcellus basis differentials to NYMEX averaged US$1.64 per Mcf in the quarter. Basis differentials have improved recently in the region, with spot price differentials in the Marcellus trading between US$1.00 per Mcf to US$1.50 per Mcf below NYMEX, due to lower NYMEX prices and the recent tie-in of new regional export pipeline capacity.

Our commodity price hedge position is largely unchanged from the previous quarter. For the fourth quarter of 2015, we have an average of 14,500 barrels per day of crude oil (approximately 45% of our expected crude oil production, net of royalties) hedged at an average floor price of US$79.47 per barrel through a combination of swaps and three-way collar structures. In 2016 we have an average of 11,000 barrels per day of crude oil (approximately 34% of our expected crude oil production, net of royalties) hedged at an average floor price of US$64.35 per barrel through a combination of swaps and three-way collar structures.

Under our gas hedging program, for the fourth quarter of 2015 we are swapped on an average of 101,739 Mcf per day against NYMEX (approximately 36% of our forecasted natural gas production, net of royalties) at an average price of US$3.97 per Mcf. In 2016 we have 25,000 Mcf per day (approximately 9% of our forecasted natural gas production, net of royalties) hedged through three-way collars with an average floor price of US$3.00 per Mcf.

Revised 2015 Guidance

We have increased our annual production guidance, reduced our capital spending guidance and decreased our operating cost and G&A expense guidance. All other guidance remains unchanged. This increased guidance assumes the divestment of a portion of our non-operated North Dakota property closes in the fourth quarter of 2015.

Summary of 2015 Expectations	Target
Capital spending	$510 million (from $540 million)
Average annual production	106,000 BOE/day (from 100,000 – 104,000 BOE/day)
Crude oil and natural gas liquids volumes	46,000 bbls/day (from 44,000 – 46,000 bbls/day)
Average royalty and production tax rate (% of gross sales, before transportation)	21%
Operating expenses	$9.00/BOE (from $9.25/BOE)
Transportation costs	$3.00/BOE
Cash G&A expenses	$2.20/BOE (from $2.25/BOE)

2016 Outlook

Our 2016 budget is focused on sustainability. Based on our continued operational success and improving capital efficiencies, we expect 2016 production to be relatively flat to 2015, despite our announced divestments, with capital spending levels significantly below those of 2015.

We have based our 2016 budget on commodity prices of US$50 per barrel WTI and US$3.00 per Mcf NYMEX. Under these assumptions, and including the proceeds of our fourth quarter divestment, we expect our capital expenditures and dividend payments to be fully funded.

Our 2016 capital budget is $350 million (down approximately 30% from 2015), with production of 100,000 – 105,000 BOE per day, including crude oil and natural gas liquids of 44,000 – 47,000 barrels per day. Our expected capital allocation will be heavily weighted to our crude oil properties at approximately 90% due to the stronger associated netback. We are maintaining flexibility to adjust capital spending based on commodity prices.

Operating costs are expected to average $9.20 per BOE in 2016, a slight increase from 2015, primarily due to the impact of a weak Canadian dollar on our U.S. dollar denominated operating costs. Our cash G&A guidance is $1.90 per BOE, down $0.30 per BOE from 2015 guidance as a result of staffing reductions in 2015 and continued cost savings initiatives.

2016 Guidance

Our 2016 guidance is based on the following assumptions: US$50 per barrel WTI, NYMEX natural gas US$3.00 per Mcf, AECO natural gas $2.85 per GJ, US/CDN exchange rate of $1.33.

Summary of 2016 Expectations	Target
Capital spending	$350 million
Average annual production	100,000 – 105,000 BOE/day
Crude oil and natural gas liquids volumes	44,000 – 47,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	22%
Operating expenses	$9.20/BOE
Transportation costs	$3.00/BOE
Cash G&A expenses	$1.90/BOE

2016 Capital Allocation	$ millions
U.S. Oil	$240
Canadian Oil	$70
Canadian Natural Gas (Deep Basin)	$20
U.S. Natural Gas (Marcellus)	$20

2016 Differential/Basis Outlook	
U.S. Bakken (compared to WTI crude oil)	US$(8.00) per barrel
Marcellus Basis (compared to NYMEX natural gas)	US$(1.25) per Mcf

* Before field transportation costs

Outlook

We delivered another quarter of consistent operational execution and disciplined capital spending which is underpinning the strength of our business. Our assets are performing well and our costs continue to decline. Our financial flexibility remains strong and we will continue to focus on improving efficiencies and sustainability as we move into 2016.

Importantly, despite the continued low commodity price environment, we remain committed to ensuring safe, responsible and sustainable operations across our business.

Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation

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

The following discussion and analysis of financial results is dated November 5, 2015 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 nine months ended September 30, 2015 and 2014 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2014 and 2013 and for the years ended December 31, 2014, 2013 and 2012; and
- our MD&A for the year ended December 31, 2014 (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" below 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 other 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 interest, unless otherwise stated. Company interest is not a term defined in Canadian National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities 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.

NON-GAAP MEASURES

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

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

Calculation of Netback ($ millions)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Oil and natural gas sales	$ 275.7	$ 456.2	$ 818.2	$ 1,455.8
Less:				
Royalties	(47.4)	(77.9)	(133.2)	(254.8)
Production taxes	(13.9)	(21.3)	(38.9)	(61.1)
Cash operating expenses(1)	(88.6)	(88.8)	(254.8)	(254.9)
Transportation costs	(30.9)	(27.9)	(85.4)	(72.9)
Netback before hedging	$ 94.9	$ 240.3	$ 305.9	$ 812.1
Cash gains/(losses) on derivative instruments	54.1	(2.5)	214.0	(42.4)
Netback after hedging	$ 149.0	$ 237.8	$ 519.9	$ 769.7

(1) Operating costs adjusted to exclude non-cash losses on fixed price electricity swaps of $1.8 million and $0.1 million in the three and nine months ended September 30, 2015 (non-cash gains of nil and $0.2 million in the three and nine months ended September 30, 2014).

"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 provided by 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 September 30, 2015	2014	Nine months ended September 30, 2015	2014
Cash flow from operating activities	$ 122.6	$ 199.1	$ 388.8	$ 568.0
Asset retirement obligation expenditures	4.2	3.3	10.6	11.8
Changes in non-cash operating working capital	(6.0)	10.4	(9.0)	66.7
Funds Flow	$ 120.8	$ 212.8	$ 390.4	$ 646.5

"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 12 months of funds flow. This measure is not equivalent to Debt to Earnings before Interest, Taxes, Depreciation and Amortization and other non-cash charges ("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 September 30, 2015	2014	Nine months ended September 30, 2015	2014
Cash dividends(1)	$ 30.9	$ 51.1	$ 109.2	$ 143.8
Capital and office expenditures	89.9	209.2	407.2	633.0
Sub-total	$ 120.8	$ 260.3	$ 516.4	$ 776.8
Funds flow	$ 120.8	$ 212.8	$ 390.4	$ 646.5
Adjusted payout ratio (%)	100%	122%	132%	120%

(1) Cash dividends exclude stock dividend plan proceeds in 2014.

In addition, the Company uses certain financial measures within the "Overview" and "Liquidity and Capital Resources" sections of this MD&A that do not have a standardized meaning or definition as prescribed by U.S. GAAP and, therefore, may not be comparable with the calculation of similar measures by other entities. Such measures include "Senior Debt to EBITDA", "Total Debt to EBITDA", "Total Debt to Capitalization", "maximum debt to consolidated present value of total proven reserves" and "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.

OVERVIEW

We continued to benefit from the momentum of our strong operational performance in the third quarter, while maintaining our balance sheet strength. We have delivered production growth and met or exceeded all of our guidance targets year-to-date. As a result, we are increasing our 2015 annual average production guidance by 4,000 BOE/day from the mid-point, reducing our capital spending guidance by $30 million and reducing our operating cost and general administrative ("G&A") expense guidance by $0.30/BOE, overall.

Production for the third quarter was 110,794 BOE/day, an increase of 3% compared to the second quarter and ahead of our annual average production guidance range of 100,000-104,000 BOE/day. Production increased by 3,365 BOE/day primarily due to additional well on-streams in our core oil play in Fort Berthold, North Dakota, where crude oil production increased by 4,795 BOE/day or 22% compared to the second quarter of 2015. With continued production outperformance in Fort Berthold, we are increasing our 2015 annual production guidance to 106,000 BOE/day and expect approximately 46,000 bbls/day of crude oil and natural gas liquids.

Our capital spending for the third quarter was $88.9 million, down from $148.0 million in the second quarter with most of our spending focused on our core crude oil plays. As a result of continued cost improvements, deferral of spending into 2016 and strong operational performance, we are decreasing our annual capital spending guidance from $540 million to $510 million.

Third quarter funds flow decreased to $120.8 million from $160.4 million in the second quarter as realized oil prices declined during the period. Our commodity price hedges continued to provide funds flow protection with cash gains of $54.1 million recorded during the quarter.

The continued decline in the twelve month average commodity price used to calculate impairments in accordance with U.S. GAAP resulted in a non-cash asset impairment charge of $321.2 million (before tax) in the quarter and $1,086.0 million (before tax) for the nine months ended September 30, 2015. Accordingly, we reported a net loss for the quarter of $292.7 million compared to a net loss of $312.5 million in the second quarter of 2015.

Operating costs for the quarter were in line with expectations at $90.4 million. As expected, we saw an increase in operating costs with seasonal turnaround activity, however on a per BOE basis, operating costs came in below guidance of $9.25/BOE at $8.87/BOE due to higher production. Cash G&A costs were in line with guidance of $2.25/BOE, at $22.8 million or $2.24/BOE, despite one-time severance charges that were incurred in the quarter. As a result of our continued focus on cost reductions and increased production guidance range, we are decreasing our operating cost guidance to $9.00/BOE and our G&A expense guidance to $2.20/BOE.

Subsequent to the quarter end, we completed a one year extension of our senior, unsecured, covenant-based bank credit facility, which now matures on October 31, 2018. As part of the extension, we chose to decrease our bank credit facility from $1.0 billion to $800 million after confirming with our syndicate banks that we could have maintained the facility at its current level. This decision balanced the need for sufficient liquidity to execute our business plan with the associated costs of maintaining a largely undrawn bank facility.

Despite the decline in commodity prices during the last year, we have remained in a strong financial position. At September 30, 2015, we had a debt to funds flow ratio of 2.0x and senior debt to EBITDA ratio of 1.8x. After a US$10.8 million senior note repayment in the fourth quarter of 2015 we have no term debt repayments until June of 2017. Subsequent to the quarter, we have taken additional steps to preserve our financial strength. We are reducing our monthly dividend to $0.03 per share from $0.05 per share effective with our December dividend payment. In addition, we have entered into an agreement to sell a portion of our non-operated North Dakota acreage for proceeds of $80 million, bringing our year to date net divestment proceeds to $283.4 million. This divestment represents less than 2% of our overall North Dakota acreage with forecast 2016 production from the existing wells of 1,000 BOE/day. We expect the sale to close during the fourth quarter. As a result of these initiatives, coupled with our continuing operational excellence, we expect to deliver a sustainable and balanced strategy for 2016.

2016 OUTLOOK

Our capital spending guidance for 2016 is $350 million, a decrease of approximately 30% from 2015 guidance of $510 million. With a focus on efficiencies and targeted spending across our core areas, we expect this spending level will allow us to essentially sustain production levels at 100,000-105,000 BOE/day, including 44,000-47,000 bbls/day of crude oil and natural gas liquids.

We expect 2016 operating expenses to average $9.20/BOE, a slight increase from $9.00/BOE in 2015, primarily due to the impact of a weak Canadian dollar on our U.S. dollar denominated operating costs and the marginal decline in production in 2016.

We are providing cash G&A guidance of $1.90/BOE, down $0.30/BOE from 2015 guidance as a result of continued cost savings initiatives and a reduction in staff.

We expect transportation costs of $3.00/BOE and an average royalty and production tax rate of 22%.

RESULTS OF OPERATIONS

Production

Production for the third quarter totaled 110,794 BOE/day, exceeding our guidance range of 100,000-104,000 BOE/day and increasing 3% compared to 107,429 BOE/day in the second quarter of 2015. This increase was driven primarily by oil production in Fort Berthold, which increased 22% or 4,795 BOE/day compared to the prior quarter. Natural gas production levels were consistent with the second quarter, with outperformance in the Marcellus offsetting a decrease in Canadian deep gas production due to scheduled turnarounds at major facilities. As a result, crude oil and natural gas liquids production in the third quarter increased to 45% of our total average daily production, up from 43% in the second quarter of 2015.

Production in the third quarter of 2015 increased 6% from 104,035 BOE/day in the same period of 2014. Crude oil production increased 11% largely due to our ongoing development program in Fort Berthold, which saw a 38% increase in crude oil production compared to the prior year. Over the same period, natural gas production increased by 2%, with growth in our Marcellus production more than offsetting the impact of our disposition of non-core gas weighted properties during the second half of 2014.

Average daily production volumes for the three and nine months ended September 30, 2015 and 2014 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2015**	**2014**	**% Change**	**2015**	**2014**	**% Change**
Crude oil (bbls/day)	44,888	40,332	11%	41,809	39,328	6%
Natural gas liquids (bbls/day)	5,061	3,869	31%	4,652	3,591	30%
Natural gas (Mcf/day)	365,071	359,007	2%	359,611	356,288	1%
Total daily sales (BOE/day)	110,794	104,035	6%	106,396	102,300	4%

As a result of continued outperformance we are revising our average annual production guidance upward to 106,000 BOE/day from 100,000-104,000 BOE/day, with approximately 46,000 bbls/day of crude oil and natural gas liquids. This increase in guidance includes lower projected fourth quarter oil production due to divestments and reduced on-stream activity in Fort Berthold.

In 2016, we expect annual average production of 100,000-105,000 BOE/day, including 44,000-47,000 bbls/day of crude oil and natural gas liquids. We expect this will be achieved despite significantly lower capital spending in 2016 and the fourth quarter sale of a portion of our North Dakota acreage.

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 the nine month period ended September 30, 2015 and 2014 and quarterly average prices from the third quarter of 2014 to the third quarter of 2015:

Pricing (average for the period)	Nine months ended September 30, 2015	2014	Q3 2015	Q2 2015	Q1 2015	Q4 2014	Q3 2014
Benchmarks							
WTI crude oil (US$/bbl)	$ 51.00	$ 99.61	$ 46.43	$ 57.94	$ 48.64	$ 73.15	$ 97.17
AECO natural gas – monthly index (CDN$/Mcf)	2.80	4.55	2.80	2.67	2.95	4.01	4.22
AECO natural gas – daily index (CDN$/Mcf)	2.77	4.81	2.90	2.64	2.75	3.60	4.02
NYMEX natural gas – last day (US$/Mcf)	2.80	4.55	2.77	2.64	2.98	4.00	4.06
US/CDN exchange rate	1.26	1.09	1.31	1.23	1.24	1.14	1.09
Enerplus Selling Price(1)							
Crude oil (CDN$/bbl)	$ 50.21	$ 92.55	$ 48.22	$ 58.26	$ 44.04	$ 69.17	$ 88.28
Natural gas liquids (CDN$/bbl)	18.60	54.79	13.51	20.88	22.48	42.34	46.76
Natural gas (CDN$/Mcf)	2.24	4.18	2.08	2.09	2.58	3.25	3.36
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (4.43)	$ (7.44)	$ (3.42)	$ (3.06)	$ (6.80)	$ (6.36)	$ (7.93)
WCS Hardisty – WTI (US$/bbl)	(13.20)	(21.12)	(13.27)	(11.59)	(14.73)	(14.24)	(20.18)
Brent Futures (ICE) – WTI (US$/bbl)	5.66	7.40	4.77	5.63	6.58	3.85	6.25
AECO monthly – NYMEX (US$/Mcf)	(0.57)	(0.40)	(0.63)	(0.47)	(0.60)	(0.47)	(0.18)
Enerplus realized differentials(1)							
Canada crude oil – WTI (US$/bbl)	$ (13.33)	$ (19.08)	$ (11.82)	$ (12.50)	$ (15.22)	$ (12.17)	$ (20.51)
Canada natural gas – NYMEX (US$/Mcf)	(0.45)	(0.26)	(0.43)	(0.46)	(0.46)	(0.62)	(0.29)
Bakken crude oil – WTI (US$/bbl)	(9.84)	(11.89)	(8.52)	(9.30)	(11.65)	(12.15)	(12.81)
Marcellus natural gas – NYMEX (US$/Mcf)	(1.46)	(1.36)	(1.64)	(1.39)	(1.32)	(1.62)	(1.70)

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

Crude Oil and Natural Gas Liquids

WTI crude oil prices fell by 20% versus the previous quarter to average US$46.43/bbl during the third quarter. Crude oil supply continued to exceed global demand. The agreement reached early in the quarter that allowed for increased Iranian crude oil exports and other sanctions relief in exchange for increased inspections and monitoring of the Iranian nuclear program exacerbated market concerns over the supply-demand imbalance, pushing oil prices sharply lower. The sell-off in crude was also driven by concerns over China's economy and the considerable losses realized in their stock market over the summer. This pushed WTI prices down to a low of US$38.24/bbl before stabilizing at approximately US$45.00/bbl by the end of the quarter.

The weakness in WTI prices and differentials was offset by a significantly weaker US/CDN dollar exchange rate. Our realized crude oil price declined by approximately 17% to average $48.22/bbl during the third quarter. The heavy crude oil differential tightened to US$7.44/bbl below WTI in July due to the impact of production outages in Northern Alberta and then widened to US$18.97/bbl as a result of a major Midwest U.S. refinery fire in late August. Light sweet crude oil price differentials experienced similar volatility due to unplanned refinery outages resulting in Canadian light sweet differentials being slightly weaker than in the second quarter averaging US$3.42/bbl below WTI.

We saw improvement in our U.S. Bakken crude oil differential during the third quarter as U.S. oil production has started to decline. Our realized Bakken differential was US$8.52/bbl below WTI compared to US$9.30/bbl below WTI in the second quarter. Subsequent to the third quarter we have seen differentials improve further. For 2016, we expect a Bakken differential of US$8.00/bbl below WTI.

The decline in crude oil prices plus the continued build in natural gas liquids inventories in the U.S. pushed benchmark prices for liquids lower once again during the third quarter. Propane stocks increased by over 9 million barrels, sending U.S. benchmark propane prices significantly lower. Propane prices in Canada continued to trade negative during the third quarter as a result of the oversupply of propane in the Canadian market. Prices for condensate in both the U.S. and Canada were also lower this quarter due to the 20% decline in WTI prices. As a result, we realized an average price for our natural gas liquids of $13.51/bbl which is a 35% decrease from the second quarter.

Natural Gas

Natural gas prices at AECO (monthly) and on the NYMEX were slightly stronger during the third quarter, both averaging 5% higher than the previous quarter. Natural gas in storage in the U.S. at September 30, 2015 was 3.6 Tcf, which is near the highest level we have seen at this time of the year relative to the past five years, and remains on track to reach 4.0 Tcf. Mild temperatures and ongoing concerns over the impact a strong El Nino weather pattern may have on natural gas demand this winter has driven current NYMEX prices lower. Our realized natural gas price in the third quarter of 2015 averaged $2.08/Mcf, which was largely unchanged from the previous quarter with weaker Marcellus differentials offsetting the strength in AECO and NYMEX prices.

Strong production levels and significant maintenance activities on the two major pipelines running through Northeast Pennsylvania contributed to continued weakness in regional Marcellus pricing during the quarter. Transco Leidy Pipeline and Tennessee Gas Pipeline Marcellus spot prices averaged US$1.71/Mcf below NYMEX. As we continue to have a significant portion of our Marcellus production linked to markets outside of the production region, our realized Marcellus gas price averaged US$1.64/Mcf below NYMEX. This was 18% lower than the second quarter. Basis differentials have improved subsequent to the quarter-end in the region, with spot prices in the Marcellus trading approximately US$1.00/Mcf to US$1.50/Mcf below NYMEX, due to weaker NYMEX prices and the recent tie-in of new regional export pipeline capacity. For 2016, we expect a Marcellus differential of US$1.25/Mcf below NYMEX.

Foreign Exchange

The Canadian dollar weakened during the third quarter, averaging US/CDN 1.31. In July, we saw the Canadian dollar fall to a six year low of 1.30 following the Bank of Canada's decision to cut interest rates by 25 basis points and lower their forecasted economic growth for 2015. The Canadian dollar continued to depreciate in August and September as a result of decreasing commodity prices, exiting the quarter at a US/CDN exchange rate of 1.34; a level not experienced since 2004. The majority of our crude oil and natural gas sales are based on U.S. dollar denominated indices and a weaker Canadian dollar relative to the U.S. dollar increases the amount of our realized sales. Because we report in Canadian dollars, the weaker Canadian dollar also increases our U.S. dollar denominated operating costs, capital spending and the principal and interest on our U.S. dollar denominated senior notes.

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. Hedging activity was minimal during the third quarter due to the current commodity price environment. For the fourth quarter of 2015, we have an average of 14,500 bbls/day of crude oil (approximately 45% of our expected crude oil production, net of royalties) hedged at an average floor price of US$79.47/bbl through a combination of swaps and three-way collar structures. In 2016 we have an average of 11,000 bbls/day of crude oil (approximately 34% of our expected crude oil production, net of royalties) hedged at an average floor price of US$64.35/bbl through a combination of swaps and three-way collar structures.

We have not added materially to our gas hedging program with prices remaining weak during the quarter. For the fourth quarter of 2015 we are swapped on an average of 101,739 Mcf/day (approximately 36% of our forecasted natural gas production, net of royalties) at an average price of US$3.97/Mcf. In 2016 we have 25,000 Mcf/day (approximately 9% of our forecasted natural gas production, net of royalties) hedged through three-way collars with an average floor price of US$3.00/Mcf.

The following is a summary of our financial contracts in place at October 22, 2015 expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[1]			NYMEX Natural Gas (US$/Mcf)[1]		
	Oct 1, 2015 – Dec 31, 2015	Jan 1, 2016 – Jun 30, 2016	Jul 1, 2016 – Dec 31, 2016	Oct 1, 2015 – Oct 31, 2015	Nov 1, 2015 – Dec 31, 2015	Jan 1, 2016 – Dec 31, 2016
Downside Protection – Swaps						
Sold Swaps	$ 82.10	$ 64.28	–	$ 3.85	$ 4.04	–
%	39%	9%	–	41%	34%	–
Downside Protection – Collars						
Sold Puts	$ 48.00	$ 50.13	$ 49.34	–	–	$ 2.50
%	6%	25%	34%	–	–	9%
Purchased Puts	$ 63.00	$ 64.38	$ 64.35	–	–	$ 3.00
%	6%	25%	34%	–	–	9%
Sold Calls	$ 70.00	$ 79.38	$ 80.09	–	–	$ 3.75
%	6%	25%	34%	–	–	9%
Upside Participation Collars						
Sold Puts	$ 62.23	–	–	$ 3.25	$ 3.25	–
%	12%	–	–	2%	2%	–
Purchased Calls	$ 93.00	–	–	$ 4.29	$ 4.29	–
%	12%	–	–	2%	2%	–
Sold Calls	–	–	–	$ 5.00	$ 5.00	–
%	–	–	–	2%	2%	–

(1) Based on weighted average price (before premiums), assumed average annual production of 106,000 BOE/day for 2015 and 100,000 – 105,000 BOE/day for 2016, less royalties and production taxes of 21.0% and 22.0% in aggregate, respectively.

We have also entered into WCS and MSW differential swap positions to manage our exposure to Canadian crude oil differentials. At October 22, 2015, we have 4,000 bbls/day of WCS swapped at US$(16.61)/bbl and 1,333 bbls/day of MSW swapped at US$(3.28)/bbl for the fourth quarter of 2015. For 2016, we have 3,000 bbls/day of WCS swapped at US$(14.03)/bbl and 1,000 bbls/day of MSW swapped at US$(3.50)/bbl.

The following table provides a summary of the physical AECO-NYMEX basis contracts we have in place at October 22, 2015:

	MMcf/day	US$/Mcf
Oct 1, 2015 – Oct 31, 2015 AECO-NYMEX Basis	60.0	$ (0.65)
Nov 1, 2015 – Oct 31, 2016 AECO-NYMEX Basis	60.0	$ (0.67)
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)

In 2014 we entered into foreign exchange collars on US$24 million per month to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and natural gas sales with upside participation in the event the Canadian dollar weakened. During the second quarter of 2015 we entered into U.S. dollar forward exchange contracts on US$6 million per month at an exchange rate of US/CDN 1.20 to partially mitigate our losses on these collars. As of October 22, 2015, we effectively have US$18 million per month hedged for 2015 at an average US/CDN floor of

1.1088, a ceiling of 1.1845 and a conditional ceiling of 1.1263. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional celling is used to determine the settlement amount. We do not have any foreign exchange contracts in place for 2016.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Commodity Risk Management Gains/(Losses) ($ millions)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash gains/(losses):				
Crude oil	$ 36.6	$ (4.2)	$ 163.8	$ (36.2)
Natural gas	17.5	1.7	50.2	(6.2)
Total cash gains/(losses)	$ 54.1	$ (2.5)	$ 214.0	$ (42.4)
Non-cash gains/(losses):				
Change in fair value – crude oil	$ 35.1	$ 82.9	$ (71.9)	$ 48.7
Change in fair value – natural gas	(8.2)	10.9	(30.4)	8.3
Total non-cash gains/(losses)	$ 26.9	$ 93.8	$ (102.3)	$ 57.0
Total gains	$ 81.0	$ 91.3	$ 111.7	$ 14.6

(Per BOE)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Total cash gains/(losses)	$ 5.31	$ (0.26)	$ 7.36	$ (1.52)
Total non-cash gains/(losses)	2.64	9.80	(3.52)	2.04
Total gains	$ 7.95	$ 9.54	$ 3.84	$ 0.52

During the third quarter of 2015 we realized cash gains of $36.6 million on our crude oil contracts and $17.5 million on our natural gas contracts. In comparison, during the third quarter of 2014 we realized cash losses of $4.2 million on our crude oil contracts and cash gains of $1.7 million on our natural gas contracts. The cash gains in 2015 were due to contracts which provided floor protection above market prices, while cash losses in 2014 were a result of prices rising above our fixed price swap positions.

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 third quarter of 2015 the fair value of our crude oil and natural gas contracts represented net gain positions of $95.3 million and $18.8 million, respectively. For the three and nine months ended September 30, 2015 the change in the fair value of our crude oil contracts represented gains of $35.1 million and losses of $71.9 million, respectively, and our natural gas contracts represented losses of $8.2 million and $30.4 million, respectively.

During the three and nine months ended September 30, 2015 we recorded total cash losses on our foreign exchange collars of $10.9 million and $26.6 million, respectively. At September 30, 2015 the fair value of foreign exchange derivatives was a net loss of $9.2 million. See Note 15 for further information.

Revenues

($ millions)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Oil and natural gas	$ 275.7	$ 456.2	$ 818.2	$ 1,455.8
Royalties	(47.4)	(77.9)	(133.2)	(254.8)
Oil and natural gas sales, net of royalties	$ 228.3	$ 378.3	$ 685.0	$ 1,201.0

Oil and natural gas revenues for the three and nine months ended September 30, 2015 were $228.3 million and $685.0 million, respectively, compared to $378.3 million and $1,201.0 million for the same periods in 2014. The decrease in revenue for both the three and nine month periods was driven primarily by the weak commodity price environment offset somewhat by an increase in production volumes.

Royalties and Production Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2015	2014	2015	2014
Royalties	$ 47.4	$ 77.9	$ 133.2	$ 254.8
Per BOE	$ 4.65	$ 8.14	$ 4.59	$ 9.12
Production taxes	$ 13.9	$ 21.3	$ 38.9	$ 61.1
Per BOE	$ 1.36	$ 2.22	$ 1.34	$ 2.19
Royalties and production taxes	$ 61.3	$ 99.2	$ 172.1	$ 315.9
Per BOE	$ 6.01	$ 10.36	$ 5.93	$ 11.31
Royalties and production taxes (% of oil and natural gas sales, before transportation)	22%	22%	21%	22%

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. During the three and nine months ended September 30, 2015 royalties and production taxes decreased to $61.3 million and $172.1 million, respectively, from $99.2 million and $315.9 million for the same periods in 2014, primarily due to lower realized prices. Royalties and production taxes as a percentage of oil and natural gas sales before transportation averaged 22% and 21% for the three and nine months ended September 30, 2015, respectively, compared to 22% for the same periods in 2014.

We continue to expect an average royalty and production tax rate of 21% in 2015 with a slight increase to 22% in 2016 as a result of increased U.S. production with a higher effective royalty and production tax rate.

Operating Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2015	2014	2015	2014
Operating expenses	$ 90.4	$ 88.9	$ 254.9	$ 254.7
Per BOE	$ 8.87	$ 9.28	$ 8.77	$ 9.12

Effective January 1, 2015 we reclassified Marcellus gathering costs from operating expenses to transportation costs. These charges relate to pipeline costs paid to third parties to transport saleable natural gas from the lease to downstream points of sale. This is a presentation change with no impact on our netback, funds flow or net income. All comparative periods have been presented to conform to the current period presentation.

For the three and nine months ended September 30, 2015 operating expenses were $90.4 million or $8.87/BOE and $254.9 million or $8.77/BOE, respectively, compared to $88.9 million or $9.28/BOE and $254.7 million or $9.12/BOE for the same periods in 2014. As expected, our third quarter 2015 operating costs increased over the previous quarter as a result of planned maintenance activity, the impact of a weakening Canadian dollar on our U.S. dollar denominated operating expenses and non-cash losses of $1.8 million on our electricity hedges. Overall, operating costs per BOE decreased during the three and nine months ended September 30, 2015 compared to the prior year due to higher production volumes and realized cost saving initiatives, offset in part by the impact of a weaker Canadian dollar.

Based on our cost savings to date and our increased production guidance, we are reducing our 2015 guidance for operating expenses to $9.00/BOE from $9.25/BOE. Although year to date operating costs are below our revised guidance, we are expecting oil production to decrease in the fourth quarter as a result of reduced on-stream activity in Fort Berthold and our fourth quarter divestment.

For 2016, we expect operating costs to average $9.20/BOE, a slight increase from 2015 operating costs per BOE. This is primarily due to the full year impact of a US/CDN exchange rate of 1.33 and a marginal decline in production in 2016.

Transportation Costs

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2015	2014	2015	2014
Transportation costs	$ 30.9	$ 27.9	$ 85.4	$ 72.9
Per BOE	$ 3.03	$ 2.92	$ 2.94	$ 2.61

As discussed previously in operating expenses, we have reclassified Marcellus gathering costs to transportation costs. This is a presentation change with no impact on our netback, funds flow or net income. All comparative periods have been presented to conform with the current period presentation.

For the three and nine months ended September 30, 2015 transportation costs were $30.9 million or $3.03/BOE and $85.4 million or $2.94/BOE, respectively, compared to $27.9 million or $2.92/BOE and $72.9 million or $2.61/BOE for the same periods in 2014. The increase in transportation costs was due to higher U.S. production and the impact of a weakening Canadian dollar on our U.S. dollar denominated costs.

We are maintaining our annual transportation cost guidance of $3.00/BOE for 2015 and 2016.

Netbacks

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

	Three months ended September 30, 2015		
Netbacks by Property Type	Crude Oil	Natural Gas	Total
Average Daily Production	52,764 BOE/day	348,180 Mcfe/day	110,794 BOE/day
Netback(1) $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 43.34	$ 2.04	$ 27.04
Royalties and production taxes	(11.02)	(0.24)	(6.01)
Cash operating expenses	(11.48)	(1.03)	(8.69)
Transportation costs	(1.74)	(0.70)	(3.03)
Netback before hedging	$ 19.10	$ 0.07	$ 9.31
Cash gains/(losses)	7.53	0.55	5.31
Netback after hedging	$ 26.63	$ 0.62	$ 14.62
Netback before hedging ($ millions)	$ 92.7	$ 2.2	$ 94.9
Netback after hedging ($ millions)	$ 129.2	$ 19.8	$ 149.0

Netbacks by Property Type	Three months ended September 30, 2014		
	Crude Oil	Natural Gas	Total
Average Daily Production	45,263 BOE/day	352,632 Mcfe/day	104,035 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 77.98	$ 4.06	$ 47.67
Royalties and production taxes	(20.73)	(0.40)	(10.36)
Cash operating expenses	(9.05)	(1.58)	(9.29)
Transportation costs	(1.91)	(0.62)	(2.92)
Netback before hedging	$ 46.29	$ 1.46	$ 25.10
Cash gains/(losses)	(1.01)	0.05	(0.26)
Netback after hedging	$ 45.28	$ 1.51	$ 24.84
Netback before hedging ($ millions)	$ 192.8	$ 47.5	$ 240.3
Netback after hedging ($ millions)	$ 188.6	$ 49.2	$ 237.8

Netbacks by Property Type	Nine months ended September 30, 2015		
	Crude Oil	Natural Gas	Total
Average Daily Production	48,930 BOE/day	344,796 Mcfe/day	106,396 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 45.62	$ 2.22	$ 28.17
Royalties and production taxes	(10.99)	(0.27)	(5.93)
Cash operating expenses	(11.99)	(1.00)	(8.77)
Transportation costs	(1.79)	(0.65)	(2.94)
Netback before hedging	$ 20.85	$ 0.30	$ 10.53
Cash gains/(losses)	12.26	0.53	7.36
Netback after hedging	$ 33.11	$ 0.83	$ 17.89
Netback before hedging ($ millions)	$ 278.4	$ 27.5	$ 305.9
Netback after hedging ($ millions)	$ 442.2	$ 77.7	$ 519.9

Netbacks by Property Type	Nine months ended September 30, 2014		
	Crude Oil	Natural Gas	Total
Average Daily Production	44,317 BOE/day	347,898 Mcfe/day	102,300 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(Per BOE)
Oil and natural gas sales	$ 84.58	$ 4.55	$ 52.13
Royalties and production taxes	(21.08)	(0.64)	(11.31)
Cash operating expenses	(11.38)	(1.23)	(9.14)
Transportation costs	(1.80)	(0.54)	(2.61)
Netback before hedging	$ 50.32	$ 2.14	$ 29.07
Cash gains/(losses)	(2.99)	(0.07)	(1.52)
Netback after hedging	$ 47.33	$ 2.07	$ 27.55
Netback before hedging ($ millions)	$ 608.9	$ 203.2	$ 812.1
Netback after hedging ($ millions)	$ 572.7	$ 197.0	$ 769.7

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

Our crude oil properties accounted for 91% of our corporate netback before hedging for the nine months ended September 30, 2015 compared to 75% for the same period in 2014. Crude oil and natural gas netbacks per BOE decreased significantly for the three and nine months ended September 30, 2015 compared to the same periods in 2014 primarily due to the decline in commodity prices. Realized cash hedging gains along with lower royalty rates and lower operating expenses helped to offset the impact of lower prices.

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 for further details.

($ millions)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash:				
G&A expense	$ 22.8	$ 18.9	$ 64.1	$ 58.1
Share-based compensation	(3.6)	(5.2)	2.5	12.3
Non-Cash:				
Share-based compensation	7.8	3.4	17.4	9.9
Equity swap loss/(gain)	2.0	5.8	1.4	(0.1)
Total G&A expenses	$ 29.0	$ 22.9	$ 85.4	$ 80.2

(Per BOE)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash:				
G&A expense	$ 2.24	$ 1.97	$ 2.21	$ 2.08
Share-based compensation	(0.35)	(0.54)	0.08	0.44
Non-Cash:				
Share-based compensation	0.77	0.36	0.60	0.35
Equity swap loss/(gain)	0.19	0.61	0.05	–
Total G&A expenses	$ 2.85	$ 2.40	$ 2.94	$ 2.87

Cash G&A expenses during the three and nine months ended September 30, 2015 were $22.8 million ($2.24/BOE) and $64.1 million ($2.21/BOE), respectively, compared to $18.9 million ($1.97/BOE) and $58.1 million ($2.08/BOE) for the same periods in 2014. The increase in cash G&A expenses compared to 2014 were a result of one-time severance payments of $8.5 million or $0.29/BOE year to date offset by cost savings.

During the quarter, our share price decreased by 41% resulting in a cash SBC recovery of $3.6 million or $0.35/BOE compared to a recovery of $5.2 million or $0.54/BOE in the same period of 2014. We recorded non-cash SBC of $7.8 million or $0.77/BOE in the third quarter compared to $3.4 million or $0.36/BOE during the same period in 2014. The increase in non-cash SBC was a result of additional grants issued under the LTI plans, along with one-time severance charges.

We have hedged a portion of the outstanding cash settled grants under our LTI plans. As a result of the decrease in our share price during the quarter we recorded a non-cash mark-to-market loss of $2.0 million on these hedges. As of September 30, 2015 we had 470,000 units hedged at a weighted average price of $16.89 per share.

As a result of cost savings realized to date, we are reducing our cash G&A guidance to $2.20/BOE from $2.25/BOE. We do not provide guidance for SBC because it is dependent on our share price and our relative performance to our peers.

For 2016, we are providing cash G&A guidance of $1.90/BOE, down $0.30/BOE or 14% from 2015 guidance as a result of staff reductions and ongoing cost savings efforts.

Interest Expense

($ millions)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Interest on senior notes and bank facility	$ 16.3	$ 14.9	$ 48.9	$ 45.5
Non-cash interest expense	0.2	0.3	0.8	1.4
Total interest expense	$ 16.5	$ 15.2	$ 49.7	$ 46.9

For the three and nine months ended September 30, 2015 we recorded total interest expense of $16.5 million and $49.7 million, respectively, compared to $15.2 million and $46.9 million for the same periods in 2014. The increase in interest expense for the three and nine month period was primarily due to the impact of a weakening Canadian dollar on our U.S. dollar denominated interest expense, along with an overall increase in senior notes with higher interest rates compared to our bank credit facility following our September 2014 private placement of US$200 million.

Non-cash amounts recorded in interest expense include amortization of deferred financing charges. See Note 11 for further details.

At September 30, 2015 approximately 91% of our debt was based on fixed interest rates and 9% on floating interest rates, with weighted average interest rates of 5.2% and 2.4%, respectively.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2015	2014	2015	2014
Realized loss/(gain)	$ 8.8	$ (2.6)	$ (18.4)	$ 14.0
Unrealized loss/(gain)	60.8	33.1	164.6	10.7
Total foreign exchange loss/(gain)	$ 69.6	$ 30.5	$ 146.2	$ 24.7
US/CDN exchange rate	1.31	1.09	1.26	1.09

For the three and nine months ended September 30, 2015 we recorded net foreign exchange losses of $69.6 million and $146.2 million, respectively, compared to losses of $30.5 million and $24.7 million for the same periods in 2014.

Realized losses of $8.8 million in the third quarter included net payments of $10.9 million on our foreign exchange collars and forward contracts offset by gains on day-to-day transactions recorded in foreign currencies. During the nine months ended September 30, 2015 we recorded realized gains of $18.4 million primarily due to a $39.9 million gain on the unwind of our US$175 million foreign exchange swaps during the first quarter which were offset by cumulative losses of $26.6 million on our foreign exchange collars caused by a continued weakening of the Canadian dollar.

Unrealized losses include the translation of U.S. dollar debt and working capital as well as changes in fair value of our foreign exchange derivatives. See Note 12 for further details.

Capital Investment

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2015	2014	2015	2014
Capital spending	$ 88.9	$ 207.8	$ 403.9	$ 630.0
Office capital	1.0	1.4	3.3	3.0
Sub-total	89.9	209.2	407.2	633.0
Property and land acquisitions	$ 2.0	$ 4.0	$ 0.8	$ 17.2
Property divestments	(11.9)	(68.9)	(203.4)	(185.6)
Sub-total	(9.9)	(64.9)	(202.6)	(168.4)
Total	$ 80.0	$ 144.3	$ 204.6	$ 464.6

Capital spending for the three and nine months ended September 30, 2015 totaled $88.9 million and $403.9 million, respectively, compared to $207.8 million and $630.0 million for the same periods in 2014. Although we slowed spending due to weak commodity prices, we continued to invest modestly in our core areas. During the third quarter we spent $58.1 million on our Fort Berthold crude oil properties, $23.9 million on our Canadian crude oil properties, $3.3 million on our Marcellus assets and $2.8 million on our deep gas properties in Canada.

We disposed of non-core Canadian oil properties in Southeast Saskatchewan during the third quarter for proceeds of $11.9 million. In the third quarter of 2014 we divested of $68.9 million of non-core natural gas properties in the deep basin area with production of approximately 1,900 BOE/day.

Subsequent to the quarter end, we entered into an agreement to sell a portion of our non-operated North Dakota properties for proceeds of $80 million. This divestment represents less than 2% of our total North Dakota acreage with forecast 2016 production from the existing wells of 1,000 BOE/day. We expect it to close during the fourth quarter. Including this sale, we have recorded year to date net divestment proceeds of $283.4 million.

Due to continued cost improvements, strong operational performance and the deferral of spending into 2016, we have reduced our 2015 guidance for capital spending to $510 million from $540 million.

For 2016, we expect capital spending to be $350 million with approximately 90% directed to oil and liquids properties. As a result of continued cost savings and efficiencies, we expect this lower capital spending budget will allow us to essentially sustain our 2015 production levels through targeted spending across our core areas, while preserving our balance sheet.

Depletion, Depreciation, Amortization and Accretion ("DDA&A")

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2015	2014	2015	2014
DDA&A expense	$ 131.5	$ 159.7	$ 401.3	$ 440.5
Per BOE	$ 12.90	$ 16.68	$ 13.81	$ 15.77

DDA&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved reserves. For the three and nine months ended September 30, 2015, DDA&A per BOE decreased when compared the same periods of 2014 primarily due to additional reserves recognized in the 2014 year-end reserves evaluation and the effect of the year to date 2015 impairments on our book value.

Impairment

Under U.S. GAAP, entities using full cost oil and gas accounting are subject to a ceiling test performed on a country by country basis using estimated after-tax future net cash flows discounted at 10% 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 reversible in future periods.

The trailing twelve month average crude oil and natural gas prices have decreased significantly over the first three quarters of 2015 and resulted in non-cash impairments for the three and nine months ended September 30, 2015 of $321.2 million and $1,086.0 million (before tax), respectively. We did not record any ceiling test impairments on our oil and natural gas properties in 2014. We expect the twelve month trailing prices used in the ceiling test calculation to decline further which may lead to additional impairments of our oil and natural gas properties. See Note 5 for trailing twelve month prices and additional information.

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 estimated by Enerplus based on our net ownership interest, anticipated 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 $286.0 million at September 30, 2015 compared to $288.7 million at December 31, 2014. The decrease is primarily due to the Pembina property divestment in the second quarter of 2015. Asset retirement obligation settlements for the three and nine months ended September 30, 2015 totaled $4.2 million and $10.6 million, respectively, compared to $3.3 million and $11.8 million for the same periods in 2014. See Note 8 for further information.

Income Taxes

($ millions)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Current tax expense/(recovery)	$ (16.2)	$ –	$ (16.2)	$ 11.4
Deferred tax expense/(recovery)	(84.9)	36.9	(445.0)	74.1
Total tax expense/(recovery)	$ (101.1)	$ 36.9	$ (461.2)	$ 85.5

We recorded a total tax recovery of $101.1 million and $461.2 million for the three and nine months ended September 30, 2015, respectively, compared to an expense of $36.9 million and $85.5 million for the same periods in 2014. The decrease in total tax expense is due primarily to lower income in 2015 which includes non-cash ceiling test impairments for Canada and the U.S. This results in an overall net deferred income tax asset of $793.6 million as at September 30, 2015. We expect to have sufficient future taxable income in both the U.S. and Canada to realize the benefit of this asset.

The current tax recovery of $16.2 million for the nine months ended September 30, 2015 increased in comparison to the $11.4 million expense that was recorded for the same period in 2014. This recovery primarily relates to an expected Alternative Tax Net Operating Loss in the U.S., which we plan to carry-back to recover Alternative Minimum Tax that was previously paid in 2013 and 2014.

These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and divestment activity.

SELECTED QUARTERLY CANADIAN AND U.S. FINANCIAL RESULTS

(CDN$ millions, except per unit amounts)	Three months ended September 30, 2015 Canada	U.S.	Total	Three months ended September 30, 2014 Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	14,478	30,410	44,888	16,837	23,495	40,332
Natural gas liquids (bbls/day)	1,731	3,330	5,061	2,578	1,291	3,869
Natural gas (Mcf/day)	131,644	233,427	365,071	154,855	204,152	359,007
Total average daily production (BOE/day)	38,150	72,644	110,794	45,224	58,811	104,035
Pricing(2)						
Crude oil (per bbl)	$ 45.31	$ 49.60	$ 48.22	$ 83.50	$ 91.71	$ 88.28
Natural gas liquids (per bbl)	25.31	7.37	13.51	46.45	47.39	46.76
Natural gas (per Mcf)	3.07	1.53	2.08	4.10	2.79	3.36
Capital expenditures						
Capital spending	$ 29.4	$ 59.5	$ 88.9	$ 55.2	$ 152.6	$ 207.8
Acquisitions	0.9	1.1	2.0	2.0	2.0	4.0
Divestments	(11.8)	(0.1)	(11.9)	(68.9)	–	(68.9)
Netback(4) Before Hedging						
Oil and natural gas sales	$ 101.8	$ 173.9	$ 275.7	$ 199.3	$ 256.9	$ 456.2
Royalties	(11.8)	(35.6)	(47.4)	(27.1)	(50.8)	(77.9)
Production taxes	(1.3)	(12.6)	(13.9)	(2.5)	(18.8)	(21.3)
Cash operating expenses	(55.9)	(32.7)	(88.6)	(64.7)	(24.1)	(88.8)
Transportation costs	(5.4)	(25.5)	(30.9)	(6.2)	(21.7)	(27.9)
Netback before hedging	$ 27.4	$ 67.5	$ 94.9	$ 98.8	$ 141.5	$ 240.3
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (81.0)	$ –	$ (81.0)	$ (91.3)	$ –	$ (91.3)
General and administrative expense(3)	23.9	5.1	29.0	19.8	3.1	22.9
Current tax expense/(recovery)	–	(16.2)	(16.2)	(0.1)	0.1	–

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

(CDN$ millions, except per unit amounts)	Nine months ended September 30, 2015 Canada	U.S.	Total	Nine months ended September 30, 2014 Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	15,629	26,180	41,809	16,867	22,461	39,328
Natural gas liquids (bbls/day)	2,073	2,579	4,652	2,531	1,060	3,591
Natural gas (Mcf/day)	137,270	222,341	359,611	154,306	201,982	356,288
Total average daily production (BOE/day)	40,580	65,816	106,396	45,116	57,184	102,300
Pricing[2]						
Crude oil (per bbl)	$ 47.41	$ 51.89	$ 50.21	$ 88.12	$ 95.88	$ 92.55
Natural gas liquids (per bbl)	29.59	9.77	18.60	57.54	48.24	54.79
Natural gas (per Mcf)	2.95	1.80	2.24	4.69	3.78	4.18
Capital expenditures						
Capital spending	$ 131.0	$ 272.9	$ 403.9	$ 243.2	$ 386.8	$ 630.0
Acquisitions	2.9	(2.1)	0.8	2.0	15.2	17.2
Divestments	(199.9)	(3.5)	(203.4)	(136.6)	(49.0)	(185.6)
Netback[4] **Before Hedging**						
Oil and natural gas sales	$ 330.4	$ 487.8	$ 818.2	$ 645.3	$ 810.5	$ 1,455.8
Royalties	(35.8)	(97.4)	(133.2)	(96.2)	(158.6)	(254.8)
Production taxes	(4.0)	(34.9)	(38.9)	(6.4)	(54.7)	(61.1)
Cash operating expenses	(162.3)	(92.5)	(254.8)	(189.1)	(65.8)	(254.9)
Transportation costs	(17.4)	(68.0)	(85.4)	(17.9)	(55.0)	(72.9)
Netback before hedging	$ 110.9	$ 195.0	$ 305.9	$ 335.7	$ 476.4	$ 812.1
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (111.7)	$ –	$ (111.7)	$ (14.6)	$ –	$ (14.6)
General and administrative expense[3]	66.6	18.8	85.4	65.7	14.5	80.2
Current tax expense/(recovery)	(0.4)	(15.8)	(16.2)	(0.5)	11.9	11.4

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

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
2015				
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	$ 685.0	$ (898.4)	$ (4.36)	$ (4.36)
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
2013				
Fourth Quarter	$ 332.4	$ 29.6	$ 0.15	$ 0.15
Third Quarter	365.4	(3.7)	(0.02)	(0.02)
Second Quarter	341.3	38.5	0.19	0.19
First Quarter	313.4	(16.4)	(0.08)	(0.08)
Total 2013	$ 1,352.5	$ 48.0	$ 0.24	$ 0.24

Oil and natural gas sales decreased during the third quarter compared to the second quarter of 2015 as commodity prices weakened, offset by increasing production. From the first quarter of 2013, oil and natural gas sales increased steadily until the third quarter of 2014 when realized commodity prices began to decline significantly. Net losses incurred during 2015 have been due to asset impairments related to the decrease in the trailing twelve month average commodity prices. We did not record any asset impairments in 2013 or 2014.

LIQUIDITY AND CAPITAL RESOURCES

There are numerous factors that influence how we assess our liquidity and leverage including commodity price cycles, capital spending levels, acquisition and divestment plans, hedging and dividend levels. We also assess our leverage relative to our most restrictive debt covenant, which is a senior debt to EBITDA threshold of 3.5x for a period of up to six months, after which it drops to 3.0x. At September 30, 2015, our senior debt to EBITDA ratio was 1.8x 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.

Our working capital deficiency, excluding cash and current deferred financial and tax balances, decreased to $135.2 million at September 30, 2015 from $260.5 million at December 31, 2014. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our adjusted payout ratio, which is calculated as cash dividends plus capital and office expenditures divided by funds flow, was 100% and 132% for the three and nine months ended September 30, 2015, respectively, compared to 122% and 120% for the same periods in 2014. We have continued to maintain our financial flexibility through an ongoing focus on cost efficiencies, the success of our non-core asset divestment program, disciplined capital spending and a reduction in dividends. After adjusting for net acquisition and divestment proceeds, our adjusted payout ratio for the three and nine months ended September 30, 2015 decreases to 92% and 80%, respectively.

Subsequent to the quarter end, we have taken additional steps to preserve our balance sheet strength. We have entered into an agreement to sell a portion of our non-operated North Dakota acreage for proceeds of $80 million. In addition, we are further reducing our monthly dividend to $0.03 per share from $0.05 per share, effective with our December 2015 payment. We expect to save approximately $50 million annually with the reduction. These initiatives, coupled with our continuing operational success, will allow us to execute our sustainable strategy for 2016.

Total debt, net of cash, at September 30, 2015 was $1,226.5 million compared to $1,134.9 million at December 31, 2014. Total debt was comprised of $113.5 million of bank indebtedness and $1,115.9 million of senior notes less $2.9 million in cash. At September 30, 2015, we were approximately 11% drawn on our $1.0 billion bank credit facility. The majority of the increase in our reported debt balance at September 30, 2015 was a result of the impact of a weakening Canadian dollar on our U.S. dollar denominated senior notes. On October 1, 2015, we paid the final installment of US$10.8 million on our maturing US$54 million senior notes. We have no additional scheduled debt repayments until June of 2017, with remaining maturities extending to 2026.

Subsequent to the quarter end, we completed a one year extension of our senior, unsecured, covenant-based bank credit facility which now matures on October 31, 2018. As part of the extension, we chose to decrease our bank credit facility to $800.0 million from $1.0 billion based on our capital spending plan for 2016 and our ongoing cost reduction initiatives. Our decision balanced the need for sufficient liquidity for executing our business plan with the associated costs of retaining a largely undrawn bank facility. We expect to realize savings of approximately $1.0 million as a result of the decreased facility size. With over 90% of our total debt comprised of term debt with no repayments until 2017 and an average drawn balance of approximately 9% of the current available capacity on our bank credit facility, we are of the view that the $1.0 billion limit provided excess capacity that is not currently required by the Company. Given our reduced 2016 capital spending plan, we intend to maintain our balance sheet strength by balancing capital spending and dividends with funds flow and non-core asset divestments as we continue to focus our portfolio. Our renewed credit facility also amends the maximum Total Debt to Capitalization ratio to 55%. Drawn fees on the facility range between 150 and 315 basis points over Banker's Acceptance rates, with current drawn fees of 170 basis points. The bank credit facility ranks equally with our senior, unsecured, covenant-based notes.

At September 30, 2015, we were in compliance with all covenants under our bank credit facility and outstanding senior notes. Our bank credit facility and senior note purchase agreements have been filed as material documents on our SEDAR profile at www.sedar.com.

The following table lists our financial covenants as at September 30, 2015:

Covenant Description		September 30, 2015
Bank Credit Facility:	**Maximum Ratio**	
Senior Debt to EBITDA	3.5 x	1.8 x
Total Debt to EBITDA	4.0 x	1.8 x
Total Debt to Capitalization(1)	50% – 55%	32%
Senior Notes:	**Maximum Ratio**	
Senior Debt to EBITDA(2)	3.0 x – 3.5 x	1.8 x
Maximum debt to consolidated present value of total proven reserves	60%	40%
	Minimum Ratio	
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.

"EBITDA" is calculated as net income less interest, taxes, depletion, depreciation, amortization, accretion and non-cash gains and losses. EBITDA is calculated on a trailing twelve month basis and is adjusted for material acquisitions and divestments. EBITDA for the three months and the trailing twelve months ended September 30, 2015 were $120.9 million and $676.0 million, respectively.

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

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

Footnotes

(1) Upon completion of a material acquisition, the Total Debt to Capitalization maximum ratio may increase to 55% for a period extending to and including the second full fiscal quarter after the completion of the acquisition. Under the renewed credit facility, the maximum ratio increases to 55%.
(2) Senior Debt to EBITDA maximum ratio for the senior notes may increase to 3.5x for a period of 6 months, after which the ratio decreases to 3.0x.

Dividends

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per share amounts)	2015	2014	2015	2014
Cash dividends	$ 30.9	$ 51.1	$ 109.2	$ 143.8
Stock dividend plan	–	4.3	–	21.8
Total dividends to shareholders	$ 30.9	$ 55.4	$ 109.2	$ 165.6
Per weighted average share (Basic)	$ 0.15	$ 0.27	$ 0.53	$ 0.81

During the three and nine months ended September 30, 2015 we reported total dividends of $30.9 million ($0.15/share) and $109.2 million ($0.53/share), respectively, compared to $55.4 million ($0.27/share) and $165.6 million ($0.81/share) for the same periods in 2014. For the three and nine months ended September 30, 2015, our cash dividends represented approximately 26% and 28% of funds flow, respectively, compared to 24% and 22% for the same periods in 2014. In September 2014 we elected to suspend our stock dividend plan, thereby eliminating any dilution resulting from issuing shares as part of our dividend plan.

To ensure financial flexibility and balance funds flow with capital and dividends we are reducing our monthly dividend to $0.03 per share from $0.05 per share, effective with the December payment. We expect to save approximately $50 million annually. 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

	Nine months ended September 30,	
	2015	2014
Share capital ($ millions)	$ 3,132.9	$ 3,115.5
Common shares outstanding (thousands)	206,496	205,423
Weighted average shares outstanding – basic (thousands)	206,100	204,174
Weighted average shares outstanding – diluted (thousands)	206,100	207,970

During the third quarter of 2015 a total of 272,000 shares (2014 – 655,000) and $6.4 million of additional equity (2014 – $12.2 million) was issued pursuant to the stock option plan, the treasury settled LTI plans and the stock dividend plan. For the nine months ended September 30, 2015 a total of 764,000 shares (2014 – 2,665,000) and $12.7 million of additional equity (2014 – $48.9 million) was issued pursuant to the stock option plan, the treasury settled LTI plans and the stock dividend plan. For further details see Note 14.

At September 30, 2015 we had 206,496,000 shares outstanding (2014 – 205,423,000) and at November 5, 2015 we had 206,496,000 shares outstanding.

2015 GUIDANCE

We have increased our annual production guidance, reduced our capital spending guidance and decreased our operating cost and cash G&A expense guidance. All other guidance has been maintained and is summarized below. This guidance includes the fourth quarter sale of a portion of our non-operated North Dakota property but does not include any additional acquisitions or divestments.

Summary of 2015 Expectations	Target
Capital spending	$510 million (from $540 million)
Average annual production	106,000 BOE/day (from 100,000 – 104,000 BOE/day)
Crude oil and natural gas liquids volumes	46,000 bbls/day (from 44,000 – 46,000 bbls/day)
Average royalty and production tax rate (% of gross sales, before transportation)	21%
Operating expenses	$9.00/BOE (from $9.25/BOE)
Transportation costs	$3.00/BOE
Cash G&A expenses	$2.20/BOE (from $2.25/BOE)

2016 GUIDANCE

This guidance includes the fourth quarter sale of a portion of our non-operated North Dakota property but does not include any additional acquisitions or divestments.

Summary of 2016 Expectations	Target
Capital spending	$350 million
Average annual production	100,000 – 105,000 BOE/day
Crude oil and natural gas liquids volumes	44,000 – 47,000 bbls/day
Average royalty and production tax rate (% of gross sales, before transportation)	22%
Operating expenses	$9.20/BOE
Transportation costs	$3.00/BOE
Cash G&A expenses	$1.90/BOE

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 September 30, 2015, 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 July 1, 2015 and ended September 30, 2015 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 2015 and 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 balance sheet and funds flow; our commodity and foreign exchange risk management programs in 2015 and in the future; the results from our drilling program and the timing of related production; oil and natural gas prices, including twelve month trailing prices used in calculation of a ceiling test impairment under U.S. GAAP; 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 2015 and 2016 and its impact on our production level; potential future asset impairments; the amount of our future abandonment and reclamation costs and asset retirement obligations; future environmental expenses; our future royalty and production and U.S. cash taxes; deferred income taxes, our tax pools and expectations regarding Canadian cash 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; our future acquisitions and dispositions, including timing thereof and expected use of proceeds therefrom; expectations regarding our measures to preserve our financial strength, including effectiveness thereof and amounts of anticipated savings therefrom; and the amount of future cash dividends that we may pay to our shareholders.

The forward-looking information contained in this MD&A reflects several material factors, 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 further curtailment of production and/or reduced realized prices; 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 our reserve and 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; the availability of third party services; and the extent of our liabilities. In addition, our 2015 guidance contained in this MD&A is based on the following September 30, 2015 forward prices: a WTI price of US$49.68/bbl, a NYMEX price of US$2.75/Mcf, an AECO price of $2.66/GJ and a CDN/USD exchange rate of 1.28. Our 2016 guidance is based on the following price assumptions: a WTI price of US$50/bbl, a NYMEX price of US$3.00/Mcf, an AECO price of $2.85/GJ, a CDN/USD exchange rate of 1.33, a Bakken crude oil differential of US$8.00/bbl below WTI and a Marcellus differential of US$1.25/Mcf below NYMEX.

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 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 in, including 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; our risk management programs, including commodity hedging, being less effective in protecting our balance sheet and funds flow than anticipated; 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; changes in estimates of our reserves and resource volumes; limited, unfavorable or a lack of access to capital markets; our inability to comply with covenants under our bank credit facility and senior notes; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; failure to complete any of the anticipated acquisitions or dispositions; 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 our Annual MD&A and in our other public filings).*

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	September 30, 2015	December 31, 2014
Assets			
Current Assets			
Cash		$ 2,916	$ 2,036
Accounts receivable	3	149,059	199,745
Deferred financial assets	15	108,145	215,706
Other current assets		12,742	8,241
		272,862	425,728
Property, plant and equipment:			
Oil and natural gas properties (full cost method)	4	1,567,927	2,632,474
Other capital assets, net	4	20,101	20,591
Property, plant and equipment		1,588,028	2,653,065
Goodwill	5	651,171	624,390
Deferred income tax asset	13	816,599	348,117
Deferred financial assets	15	9,423	30,997
Total Assets		$ 3,338,083	$ 4,082,297
Liabilities			
Current liabilities			
Accounts payable	6	$ 272,259	$ 351,006
Dividends payable		10,325	18,516
Current portion of long-term debt	7	14,466	98,933
Deferred income tax liability	13	22,996	50,805
Deferred financial liabilities	15	18,930	10,826
		338,976	530,086
Deferred financial liabilities	15	–	2,396
Long-term debt	7	1,215,002	1,037,997
Asset retirement obligation	8	286,027	288,692
		1,501,029	1,329,085
Total Liabilities		1,840,005	1,859,171
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: September 30, 2015 – 206 million shares December 31, 2014 – 206 million shares	14	3,132,923	3,120,002
Paid-in capital	14	54,562	46,906
Accumulated deficit		(2,046,914)	(1,039,260)
Accumulated other comprehensive income/(loss)		357,507	95,478
		1,498,078	2,223,126
Total Liabilities & Equity		$ 3,338,083	$ 4,082,297
Contingencies	16		
Subsequent events	18		

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 September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Revenues					
Oil and natural gas sales, net of royalties	9	$ 228,271	$ 378,332	$ 684,961	$ 1,200,997
Commodity derivative instruments gain/(loss)	15	81,032	91,268	111,679	14,602
		309,303	469,600	796,640	1,215,599
Expenses					
Production taxes		13,913	21,270	38,946	61,116
Operating		90,405	88,853	254,876	254,728
Transportation		30,879	27,907	85,380	72,870
General and administrative	10	29,028	22,937	85,370	80,240
Depletion, depreciation, amortization and accretion		131,498	159,658	401,251	440,494
Asset impairment	5	321,150	–	1,086,008	–
Interest	11	16,514	15,175	49,668	46,876
Foreign exchange (gain)/loss	12	69,638	30,498	146,184	24,742
Other expense/(income)		70	(953)	8,597	1,599
		703,095	365,345	2,156,280	982,665
Income/(loss) before taxes		(393,792)	104,255	(1,359,640)	232,934
Current income tax expense/(recovery)	13	(16,202)	(28)	(16,241)	11,447
Deferred income tax expense/(recovery)	13	(84,924)	36,853	(444,983)	74,063
Net Income/(Loss)		$ (292,666)	$ 67,430	$ (898,416)	$ 147,424
Other Comprehensive Income/(Loss)					
Changes due to marketable securities (net of tax)					
Unrealized gain/(loss)		–	–	–	(145)
Realized (gain)/loss reclassified to net income		–	–	–	2,503
Change in cumulative translation adjustment		115,759	78,459	262,029	80,689
Other Comprehensive Income/(Loss)		115,759	78,459	262,029	83,047
Total Comprehensive Income/(Loss)		$ (176,907)	$ 145,889	$ (636,387)	$ 230,471
Net income/(loss) per share					
Basic	14	$ (1.42)	$ 0.33	$ (4.36)	$ 0.72
Diluted	14	$ (1.42)	$ 0.32	$ (4.36)	$ 0.71

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

Condensed Consolidated Statements of Changes in Shareholders' Equity

Nine months ended September 30 (CDN$ thousands) unaudited	**2015**	**2014**
Share Capital		
Balance, beginning of year	$ 3,120,002	$ 3,061,839
Stock Option Plan – cash	3,205	27,068
Share-based compensation – settled	9,449	–
Stock Option Plan – exercised	267	4,783
Stock Dividend Plan	–	21,837
Balance, end of period	$ 3,132,923	$ 3,115,527
Paid-in Capital		
Balance, beginning of year	$ 46,906	$ 38,398
Share-based compensation – settled	(9,449)	–
Stock Option Plan – exercised	(267)	(4,783)
Share-based compensation – non-cash	17,372	9,907
Balance, end of period	$ 54,562	$ 43,522
Accumulated Deficit		
Balance, beginning of year	$ (1,039,260)	$ (1,117,238)
Net income/(loss)	(898,416)	147,424
Dividends	(109,238)	(165,587)
Balance, end of period	$ (2,046,914)	$ (1,135,401)
Accumulated Other Comprehensive Income/(Loss)		
Balance, beginning of year	$ 95,478	$ (50,697)
Changes due to marketable securities (net of tax)		
Unrealized gain/(loss)	–	(145)
Realized (gain)/loss reclassified to net income	–	2,503
Change in cumulative translation adjustment	262,029	80,689
Balance, end of period	$ 357,507	$ 32,350
Total Shareholders' Equity	$ 1,498,078	$ 2,055,998

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

Condensed Consolidated Statements of Cash Flows

		Three months ended September 30,		Nine months ended September 30,	
(CDN$ thousands) unaudited	Note	2015	2014	2015	2014
Operating Activities					
Net income/(loss)		$ (292,666)	$ 67,430	$ (898,416)	$ 147,424
Non-cash items add/(deduct):					
Depletion, depreciation, amortization and accretion		131,498	159,658	401,251	440,494
Asset impairment	5	321,150	–	1,086,008	–
Changes in fair value of derivative instruments	15	(26,395)	(88,689)	134,842	(81,750)
Deferred income tax expense/(recovery)	13	(84,924)	36,853	(444,983)	74,063
Foreign exchange (gain)/loss on debt and working capital	12	64,148	33,863	133,536	35,798
Share-based compensation	14	7,793	3,413	17,372	9,907
Amortization of debt issue costs		241	251	721	744
Asset divestments (gain)/loss		–	–	–	2,798
Derivative settlement on senior notes		–	–	(39,904)	17,024
Asset retirement obligation expenditures	8	(4,172)	(3,299)	(10,631)	(11,831)
Changes in non-cash operating working capital	17	5,994	(10,435)	9,045	(66,710)
Cash flow from operating activities		122,667	199,045	388,841	567,961
Financing Activities					
Proceeds from the issuance of shares	14	–	7,875	3,205	27,068
Cash dividends	14	(30,944)	(51,088)	(109,238)	(143,750)
Change in bank credit facility		33,192	(236,013)	33,626	(159,303)
Issue of/(repayment of) senior notes		–	217,460	(88,897)	179,562
Derivative settlement on senior notes		–	–	39,904	(17,024)
Changes in non-cash financing working capital		14	34	(8,191)	238
Cash flow from financing activities		2,262	(61,732)	(129,591)	(113,209)
Investing Activities					
Capital and office expenditures		(89,902)	(209,197)	(407,229)	(633,013)
Property and land acquisitions		(2,005)	(3,986)	(758)	(17,186)
Property divestments		11,865	68,931	203,378	185,631
Sale of marketable securities		–	–	–	13,300
Changes in non-cash investing working capital		(40,697)	5,116	(51,914)	(5,689)
Cash flow from investing activities		(120,739)	(139,136)	(256,523)	(456,957)
Effect of exchange rate changes on cash		(2,276)	1,929	(1,847)	1,319
Change in cash		1,914	106	880	(886)
Cash, beginning of period		1,002	1,998	2,036	2,990
Cash, end of period		$ 2,916	$ 2,104	$ 2,916	$ 2,104

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 November 5, 2015.

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 nine months ended September 30, 2015 and the 2014 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, 2014. 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, 2014.

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)	September 30, 2015	December 31, 2014
Accrued receivables	$ 101,897	$ 136,949
Accounts receivable – trade	27,338	41,618
Current income tax receivable	22,566	23,900
Allowance for doubtful accounts	(2,742)	(2,722)
Total accounts receivable	$ 149,059	$ 199,745

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

As at September 30, 2015 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 13,415,111	$ (11,847,184)	$ 1,567,927
Other capital assets	103,401	(83,300)	20,101
Total PP&E	$ 13,518,512	$ (11,930,484)	$ 1,588,028

As at December 31, 2014 ($ thousands)	Cost	Accumulated Depletion, Depreciation, and Impairment	Net Book Value
Oil and natural gas properties	$ 12,478,953	$ (9,846,479)	$ 2,632,474
Other capital assets	97,893	(77,302)	20,591
Total PP&E	$ 12,576,846	$ (9,923,781)	$ 2,653,065

5) IMPAIRMENT

a) Impairment of PP&E

($ thousands)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Oil and natural gas properties:				
Canada cost centre	$ 258,600	$ –	$ 286,700	$ –
U.S. cost centre	62,550	–	799,308	–
Total impairment expense	$ 321,150	$ –	$1,086,008	$ –

The impairments for the three and nine months ended September 30, 2015 were due to lower 12-month average trailing crude oil and natural gas prices.

The following table outlines the 12-month average trailing benchmark prices and exchange rates used in Enerplus' ceiling tests from September 30, 2014 through September 30, 2015:

Period	WTI Crude Oil US$/bbl	Exchange Rate US/CDN	Edm Light Crude CDN$/bbl	U.S. Henry Hub Gas US$/Mcf	AECO Natural Gas Spot CDN$/Mcf
Q3 2015	$ 59.21	1.22	$ 66.51	$ 3.08	$ 3.00
Q2 2015	71.75	1.16	75.83	3.42	3.33
Q1 2015	82.73	1.14	84.61	3.88	3.86
Q4 2014	94.99	1.09	94.84	4.30	4.60
Q3 2014	99.08	1.08	95.97	4.23	4.42

b) Goodwill Impairment

Goodwill impairment testing is performed annually or more frequently if events or changes in circumstances indicate that goodwill may be impaired. We have assessed potential indicators of impairment as at September 30, 2015 and find that no impairment to goodwill is required.

6) ACCOUNTS PAYABLE

($ thousands)	September 30, 2015	December 31, 2014
Accrued payables	$ 192,996	$ 239,773
Accounts payable – trade	79,263	111,233
Total accounts payable	$ 272,259	$ 351,006

7) DEBT

($ thousands)	September 30, 2015	December 31, 2014
Current:		
Senior notes	$ 14,466	$ 98,933
	14,466	98,933
Long-term:		
Bank credit facility	$ 113,543	$ 79,917
Senior notes	1,101,459	958,080
	1,215,002	1,037,997
Total debt	$ 1,229,468	$ 1,136,930

8) ASSET RETIREMENT OBLIGATION

Enerplus has estimated the present value of its asset retirement obligation to be $286.0 million at September 30, 2015 compared to $288.7 million at December 31, 2014 based on a total undiscounted liability of $702.3 million and $730.9 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.93% (December 31, 2014 – 5.92%).

($ thousands)	Nine months ended September 30, 2015	Year ended December 31, 2014
Balance, beginning of year	$ 288,692	$ 291,761
Change in estimates	9,139	4,378
Property acquisitions and development activity	711	1,778
Dispositions	(14,245)	(4,313)
Settlements	(10,631)	(19,409)
Accretion expense	12,361	14,497
Balance, end of period	$ 286,027	$ 288,692

9) OIL AND NATURAL GAS SALES

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2015	2014	2015	2014
Oil and natural gas sales	$ 275,663	$ 456,215	$ 818,173	$1,455,790
Royalties(1)	(47,392)	(77,883)	(133,212)	(254,793)
Oil and natural gas sales, net of royalties	$ 228,271	$ 378,332	$ 684,961	$1,200,997

(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 September 30,		Nine months ended September 30,	
($ thousands)	2015	2014	2015	2014
General and administrative expense	$ 22,827	$ 18,854	$ 64,134	$ 58,055
Share-based compensation expense	6,201	4,083	21,236	22,185
General and administrative expense	$ 29,028	$ 22,937	$ 85,370	$ 80,240

11) INTEREST EXPENSE

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2015	2014	2015	2014
Realized:				
Interest on bank debt and senior notes	$ 16,273	$ 14,924	$ 48,947	$ 45,552
Unrealized:				
Cross currency interest rate swap (gain)/loss	–	–	–	580
Amortization of debt issue costs	241	251	721	744
Interest expense	$ 16,514	$ 15,175	$ 49,668	$ 46,876

12) FOREIGN EXCHANGE

($ thousands)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Realized:				
Foreign exchange (gain)/loss	$ 8,786	$ (2,607)	$ (18,350)	$ 14,069
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	64,148	33,863	133,536	35,798
Cross currency interest rate swap (gain)/loss	–	–	–	(16,130)
Foreign exchange derivatives (gain)/loss	(3,296)	(758)	30,998	(8,995)
Foreign exchange (gain)/loss	$ 69,638	$ 30,498	$ 146,184	$ 24,742

13) INCOME TAXES

($ thousands)	Three months ended September 30, 2015	2014	Nine months ended September 30, 2015	2014
Current tax expense/(recovery)				
Canada	$ 3	$ (79)	$ (397)	$ (453)
United States	(16,205)	51	(15,844)	11,900
Current tax expense/(recovery)	(16,202)	(28)	(16,241)	11,447
Deferred tax expense/(recovery)				
Canada	$ (62,778)	$ 24,530	$ (99,717)	$ 19,212
United States	(22,146)	12,323	(345,266)	54,851
Deferred tax expense/(recovery)	(84,924)	36,853	(444,983)	74,063
Income tax expense/(recovery)	$ (101,126)	$ 36,825	$ (461,224)	$ 85,510

The difference between the expected income taxes based on the statutory income tax rate and the effective income taxes for the current and prior period is impacted by the following: expected annual earnings, foreign rate differentials for foreign operations, statutory and other rate differentials, the reversal or recognition of previously unrecognized deferred tax assets, non-taxable portions of capital gains and losses, and non-deductible share-based compensation.

The net deferred income tax asset at September 30, 2015 includes a current deferred income tax liability of $23.0 million (December 31, 2014 – $50.8 million) and a long-term deferred income tax asset of $816.6 million (December 31, 2014 – $348.1 million). We have evaluated our overall net deferred income tax asset of $793.6 million as at September 30, 2015 (December 31, 2014 – $297.3 million) and expect that we will have sufficient future taxable income to realize the benefit of this asset.

14) SHAREHOLDERS' EQUITY

a) Share Capital

	Nine months ended September 30, 2015		Year ended December 31, 2014	
Authorized unlimited number of common shares Issued: (thousands)	Shares	Amount	Shares	Amount
Balance, beginning of year	205,732	$ 3,120,002	202,758	$ 3,061,839
Issued for cash:				
Stock Option Plan	234	3,205	1,944	31,350
Non-cash:				
Share-based compensation – settled	530	9,449	–	–
Stock Option Plan – exercised	–	267	–	4,978
Stock Dividend Plan(1)	–	–	1,030	21,835
Balance, end of period	206,496	$ 3,132,923	205,732	$ 3,120,002

(1) Effective with the October 2014 dividend, Enerplus suspended the Stock Dividend Plan.

b) Dividends

($ thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash dividends	$ 30,944	$ 51,088	$ 109,238	$ 143,750
Stock dividends[1]	–	4,350	–	21,837
Dividends to shareholders	$ 30,944	$ 55,438	$ 109,238	$ 165,587

(1) Effective with the October 2014 dividend, Enerplus suspended the Stock Dividend Plan.

c) Share-based Compensation

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

($ thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Cash:				
Long-term incentive plans expense	$ (3,565)	$ (5,174)	$ 2,458	$ 12,338
Non-cash:				
Long-term incentive plans expense	7,649	2,815	16,698	6,506
Stock option plan expense	144	598	674	3,401
Equity swap (gain)/loss	1,973	5,844	1,406	(60)
Share-based compensation expense	$ 6,201	$ 4,083	$ 21,236	$ 22,185

(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 will continue to be settled in cash.

The following table summarizes the PSU, RSU and Director Share Unit ("DSU") activity for the nine months ended September 30, 2015:

For the nine months ended September 30, 2015 (thousands of units)	Cash-settled LTI plans PSU	Cash-settled LTI plans RSU	Cash-settled LTI plans DSU	Equity-settled LTI Plans PSU	Equity-settled LTI Plans RSU	Total
Balance, beginning of year	406	398	122	510	775	2,211
Granted	–	–	77	987	1,447	2,511
Vested	(168)	(268)	(19)	(213)	(317)	(985)
Forfeited	(10)	(29)	–	(36)	(142)	(217)
Balance, end of period	228	101	180	1,248	1,763	3,520

Cash-settled LTI Plans

For the three and nine months ended September 30, 2015 the Company recorded a cash share-based compensation recovery of $3.6 million and an expense of $2.5 million, respectively (2014 – $5.2 million recovery and $12.3 million expense). For the same periods, the Company made cash payments of $3.0 and $8.6 million, respectively, related to its cash-settled plans (September 30, 2014 – $2.0 million and $13.8 million).

The following table summarizes the cumulative cash share-based compensation expense recognized to-date, which has been recorded to Accounts Payable on the Consolidated Balance Sheets. Unrecognized amounts will be recorded to cash share-based compensation expense over the remaining vesting terms.

At September 30, 2015 ($ thousands, except for years)	**PSU**[(1)]	**RSU**	**DSU**	**Total**
Cumulative recognized share-based compensation expense	$ 3,609	$ 785	$ 1,526	$ 5,920
Unrecognized share-based compensation expense	328	127	–	455
Intrinsic value	$ 3,937	$ 912	$ 1,526	$ 6,375
Weighted-average remaining contractual term (years)	0.3	0.4	–	

(1) Includes estimated performance multipliers.

Equity-settled LTI Plans

For the three and nine months ended September 30, 2015 the Company recorded non-cash long-term incentive plans expense of $7.7 million and $16.7 million, respectively (2014 – $2.8 million and $6.5 million).

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 September 30, 2015 ($ thousands, except for years)	**PSU**[(1)]	**RSU**	**Total**
Cumulative recognized share-based compensation expense	$ 5,761	$ 10,867	$ 16,628
Unrecognized share-based compensation expense	8,662	12,338	21,000
Fair value	$ 14,423	$ 23,205	$ 37,628
Weighted-average remaining contractual term (years)	1.9	1.4	

(1) Includes estimated performance multipliers.

(ii) Stock Option Plan

The Company did not grant any stock options for the three and nine months ended September 30, 2015. The following table summarizes the stock option plan activity for the period ended September 30, 2015:

Period ended September 30, 2015	**Number of Options** (thousands)	**Weighted Average Exercise Price**
Options outstanding, beginning of year	10,368	$ 18.65
Granted	–	–
Exercised	(234)	13.71
Forfeited	(774)	19.96
Options outstanding, end of period	9,360	$ 18.67
Options exercisable, end of period	8,087	$ 19.38

At September 30, 2015 8,087,000 options were exercisable at a weighted average reduced exercise price of $19.38 with a weighted average remaining contractual term of 3.5 years, giving an aggregate intrinsic value of nil (2014 – 4 years and $17.4 million). The intrinsic value of options exercised for the three and nine months ended September 30, 2015 was nil and $0.2 million, respectively (September 30, 2014 – $4.3 million and $12.4 million).

At September 30, 2015 the total share-based compensation expense related to non-vested options not yet recognized was $0.2 million. The expense is expected to be recognized in net income over a weighted-average period of 0.4 years.

d) Paid-in Capital

The following table summarizes the paid-in capital activity for the nine months ended September 30, 2015 and the year ended December 31, 2014:

($ thousands)	Nine months ended September 30, 2015	Year Ended December 31, 2014
Balance, beginning of year	$ 46,906	$ 38,398
Share-based compensation – settled	(9,449)	–
Stock Option Plan – exercised	(267)	(4,978)
Share-based compensation – non-cash	17,372	13,486
Balance, end of period	$ 54,562	$ 46,906

e) Basic and Diluted Earnings Per Share

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

	Three months ended September 30,		Nine months ended September 30,	
(thousands, except per share amounts)	2015	2014	2015	2014
Net income/(loss)	$ (292,666)	$ 67,430	$ (898,416)	$ 147,424
Weighted average shares outstanding – Basic	206,243	205,164	206,100	204,174
Dilutive impact of share-based compensation(1)	–	3,933	–	3,796
Weighted average shares outstanding – Diluted	206,243	209,097	206,100	207,970
Net income/(loss) per share				
Basic	$ (1.42)	$ 0.33	$ (4.36)	$ 0.72
Diluted(1)	$ (1.42)	$ 0.32	$ (4.36)	$ 0.71

(1) For the three and nine months ended September 30, 2015 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 September 30, 2015 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 September 30, 2015 senior notes had a carrying value of $1,115.9 million and a fair value of $1,225.6 million (December 31, 2014 – $1,057.0 million and $1,150.0 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 nine months ended September 30, 2015 and 2014:

Gain/(Loss) ($ thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014	Income Statement Presentation
Cross Currency Interest Rate Swap					
Interest	$ –	$ –	$ –	$ (580)	Interest expense
Foreign Exchange	–	–	–	16,130	Foreign exchange
Foreign Exchange Derivatives	3,296	758	(30,998)	8,995	Foreign exchange
Electricity Swaps	(1,855)	22	(141)	204	Operating expense
Equity Swaps	(1,973)	(5,844)	(1,406)	60	General and administrative expense
Commodity Derivative Instruments:					
Oil	35,135	82,874	(71,909)	48,671	Commodity derivative instruments
Gas	(8,208)	10,879	(30,388)	8,270	
Total	$ 26,395	$ 88,689	$ (134,842)	$ 81,750	

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

($ thousands)	Three months ended September 30, 2015	Three months ended September 30, 2014	Nine months ended September 30, 2015	Nine months ended September 30, 2014
Change in fair value gain/(loss)	$ 26,927	$ 93,753	$ (102,297)	$ 56,941
Net realized cash gain/(loss)	54,105	(2,485)	213,976	(42,339)
Commodity derivative instruments gain/(loss)	$ 81,032	$ 91,268	$ 111,679	$ 14,602

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

	September 30, 2015			December 31, 2014			
	Assets		Liabilities	Assets		Liabilities	
($ thousands)	Current	Long-term	Current	Current	Long-term	Current	Long-term
Foreign Exchange Derivatives	$ 3,444	$ –	$ 12,595	$ 1,616	$ 28,665	$ 8,434	$ –
Electricity Swaps	–	–	1,508	–	–	1,368	–
Equity Swaps	–	–	4,827	–	–	1,024	2,396
Commodity Derivative Instruments:							
Oil	85,855	9,423	–	167,187	–	–	–
Gas	18,846	–	–	46,903	2,332	–	–
Total	$ 108,145	$ 9,423	$ 18,930	$ 215,706	$ 30,997	$ 10,826	$ 2,396

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 October 22, 2015:

Crude Oil Instruments:

Instrument Type(1)	bbls/day	US$/bbl
Oct 1, 2015 – Nov 30, 2015		
WTI Swap	12,500	82.10
WTI Purchased Put	2,000	63.00
WTI Sold Call	2,000	70.00
WTI Purchased Call	4,000	93.00
WTI Sold Put	6,000	57.49
WCS Differential Swap	4,000	(16.61)
MSW Differential Swap	1,000	(3.50)
Dec 1, 2015 – Dec 31, 2015		
WTI Swap	12,500	82.10
WTI Purchased Put	2,000	63.00
WTI Sold Call	2,000	70.00
WTI Purchased Call	4,000	93.00
WTI Sold Put	6,000	57.49
WCS Differential Swap	4,000	(16.61)
MSW Differential Swap	2,000	(3.05)
Jan 1, 2016 – Jun 30, 2016		
WTI Swap	3,000	64.28
WTI Purchased Put	8,000	64.38
WTI Sold Call	8,000	79.38
WTI Sold Put	8,000	50.13
WCS Differential Swap	3,000	(14.03)
Jul 1, 2016 – Dec 31, 2016		
WTI Purchased Put	11,000	64.35
WTI Sold Call	11,000	80.09
WTI Sold Put	11,000	49.34
WCS Differential Swap	3,000	(14.03)

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

Natural Gas Instruments:

Instrument Type	MMcf/day	US$/Mcf
Oct 1, 2015 – Oct 31, 2015		
NYMEX Swap	115.0	3.85
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00
Nov 1, 2015 – Dec 31, 2015		
NYMEX Swap	95.0	4.04
NYMEX Purchased Call	5.0	4.29
NYMEX Sold Put	5.0	3.25
NYMEX Sold Call	5.0	5.00
Jan 1, 2016 – Dec 31, 2016		
NYMEX Purchased Put	25.0	3.00
NYMEX Sold Put	25.0	2.50
NYMEX Sold Call	25.0	3.75

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Oct 1, 2015 – Dec 31, 2015		
AESO Power Swap	16.0	48.30
Jan 1, 2016 – Dec 31, 2016		
AESO Power Swap	15.0	46.60
Jan 1, 2016 – Dec 31, 2016		
AESO Power Swap	6.0	44.38

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

Physical Contracts:

Instrument Type	MMcf/day	US$/Mcf
Oct 1, 2015 – Oct 31, 2015	60.0	(0.65)
AECO-NYMEX Basis		
Nov 1, 2015 – Oct 31, 2016	60.0	(0.67)
AECO-NYMEX Basis		
Nov 1, 2016 – Oct 31, 2017	80.0	(0.65)
AECO-NYMEX Basis		
Nov 1, 2017 – Oct 31, 2018	80.0	(0.65)
AECO-NYMEX Basis		
Nov 1, 2018 – Oct 31, 2019	80.0	(0.64)
AECO-NYMEX Basis		

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. Enerplus manages currency risk through the derivative instruments detailed below.

Foreign Exchange Derivatives:

During 2015 Enerplus entered into foreign exchange forward rate swaps for July through December 2015 to buy US$6 million per month at an average US/CDN exchange rate of 1.20 to partially mitigate losses on the foreign exchange collars entered into in 2014.

During 2014 Enerplus entered into foreign exchange collars to protect a portion of its foreign exchange exposure on U.S. dollar denominated oil and gas sales with upside participation in the event the Canadian dollar weakened. As of September 30, 2015 we have US$24 million per month hedged for the remainder of 2015 at an average US/CDN floor of 1.1088, a ceiling of 1.1845 and a conditional ceiling of 1.1263.

During 2011 Enerplus entered into foreign exchange swaps on US$175.0 million of notional debt at approximately par. During 2015 Enerplus unwound these swaps and recognized a gain of $39.9 million and an offsetting non-cash loss of $27.6 million which have been included in foreign exchange gain/loss on the Consolidated Statements of Income/(Loss).

During 2007 Enerplus entered into foreign exchange swaps on US$54.0 million of notional debt at an average US/CDN exchange rate of 1.02. The remaining US$10.8 million notional amount under the swap matures in October 2015 in conjunction with the final principal repayment on the US$54.0 million senior notes.

Interest Rate Risk:

At September 30, 2015 approximately 91% of Enerplus' debt was based on fixed interest rates and 9% was based on floating interest rates. At September 30, 2015 Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its long-term incentive plans detailed in Note 14. Enerplus has entered into various equity swaps maturing between 2015 and 2017 and has effectively fixed the final 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 September 30, 2015 approximately 59% of Enerplus' marketing receivables were with companies considered investment grade.

At September 30, 2015 approximately $3.2 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 September 30, 2015 was $2.7 million (December 31, 2014 – $2.7 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 September 30, 2015 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 September 30,		Nine months ended September 30,	
($ thousands)	2015	2014	2015	2014
Accounts receivable	$ 1,347	$ 6,858	$ 20,043	$ (13,019)
Other current assets	9,657	(5,754)	(5,220)	(5,210)
Accounts payable	(5,010)	(11,539)	(5,778)	(48,481)
	$ 5,994	$ (10,435)	$ 9,045	$ (66,710)

b) Other

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	2015	2014	2015	2014
Income taxes paid/(received)	$ (972)	$ (254)	$ (20,169)	$ 18,133
Interest paid	$ 6,428	$ 4,138	$ 38,846	$ 32,826

18) SUBSEQUENT EVENTS

The following events occurred subsequent to September 30, 2015:

Enerplus entered into an agreement to sell a portion of its non-operated interest in North Dakota crude oil assets for proceeds of approximately $80 million, before closing adjustments. This divestment is expected to close in 2015.

Enerplus' Board of Directors approved a reduction in its monthly dividend from $0.05 per share to $0.03 per share, effective with the December dividend.

Enerplus extended its senior unsecured bank credit facility to October 31, 2018, and requested a reduction in the committed capacity from $1 billion to $800 million.

BOARD OF DIRECTORS

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Boerne, Texas

David H. Barr[9][12]
Corporate Director
The Woodlands, Texas

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Progress Energy Canada Ltd.
Calgary, Alberta

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

Hilary A. Foulkes[5][9][11]
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Corporate Director
Calgary, Alberta

Glen D. Roane[4][5]
Corporate Director
Canmore, Alberta

Sheldon B. Steeves[5][8]
Corporate Director
Calgary, Alberta

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

OFFICERS

ENERPLUS CORPORATION

Ian C. Dundas
President & Chief Executive Officer

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

Kenneth W. Young
Vice President, Land & Operations Services

Shaina B. Morihira
Corporate Controller, Finance

CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS CORPORATION

Enerplus Resources (USA) Corporation

LEGAL COUNSEL

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AUDITORS

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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

Enerplus is a North American energy producer with a portfolio of high quality oil and gas assets in resource plays that offer significant organic growth potential. We are focused on creating value for our investors through the execution of a disciplined capital investment strategy that supports the successful development of our properties, and a monthly dividend to shareholders. We are a responsible developer of resources that strives to provide investors with a competitive return comprised of both growth and income.

ERF LISTED ON TMX Toronto Stock Exchange

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