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

The following discussion and analysis of financial results is dated November 6, 2014 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, 2014 and 2013 (the "Interim Financial Statements");
- the audited consolidated financial statements of Enerplus as at December 31, 2013 and 2012 and for the years ended December 31, 2013, 2012 and 2011 (the "Financial Statements"); and
- our MD&A for the year ended December 31, 2013 (the "Annual MD&A").

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

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.

BASIS OF PRESENTATION

The Interim Financial Statements and notes have been prepared in accordance with accounting principles generally accepted in the United States of America ("U.S. GAAP") including the prior period comparatives. All amounts are stated in Canadian dollars unless otherwise specified.

In accordance with U.S. GAAP, oil and gas sales are presented net of royalties in our Interim Financial Statements. Under IFRS, 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 revenue (net of transportation), less royalties, production taxes and cash operating costs.

"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 but before asset retirement obligation expenditures and changes in non-cash operating working capital.

	Three months ended September 30,		Nine months ended September 30,	
Reconciliation of Cash Flow from Operating Activities to Funds Flow	**2014**	**2013**	**2014**	**2013**
Cash flow from operating activities	$ 199,045	$ 218,170	$ 567,961	$ 574,828
Asset retirement obligation expenditures	3,299	3,701	11,831	10,036
Changes in non-cash operating working capital	10,435	(25,684)	66,710	(11,372)
Funds flow	$ 212,779	$ 196,187	$ 646,502	$ 573,492

"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.

"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 dividends to shareholders, net of our Stock Dividend Program ("SDP") proceeds, plus capital spending (including office capital) divided by funds flow.

OVERVIEW

Production for the third quarter averaged 104,035 BOE/day, consistent with the prior quarter and an increase of 19% compared to the same period in 2013. Crude oil and natural gas liquids production grew by 2% compared to the prior quarter, while natural gas volumes were essentially flat. Low natural gas prices and pipeline maintenance resulted in production curtailments of approximately 3,000-4,000 BOE/day in the Marcellus during the quarter. Despite these interruptions, average production volumes for the year to date are ahead of expectations and we have increased our guidance again for 2014 to 102,000-104,000 BOE/day from 100,000-104,000 BOE/day.

Our capital spending program continued to focus on our core development areas, with $207.8 million spent in the third quarter. As discussed in our second quarter release, the successful divestment of approximately $91.0 million of non-core assets in the second half of 2014 has provided us with additional flexibility and we have redeployed a portion of the divestment proceeds to accelerate our 2015 capital program in our core areas. Accordingly, we have increased our capital spending guidance for 2014 to $830 million from $800 million.

Funds flow for the third quarter totaled $212.8 million compared to $213.2 million in the second quarter and $196.2 million in the same period in 2013. In the third quarter our funds flow was impacted by lower commodity prices however this was partially offset by cash share-based compensation recoveries given the industry wide sell off in equities. Lower commodity prices at quarter end resulted in a $93.8 million non-cash gain on our commodity derivatives which contributed to a nearly 70% increase in our net income compared to the second quarter.

Cash general and administrative expenses for the quarter of $1.97/BOE were consistent with the second quarter. Operating costs increased to $10.67/BOE, compared to $10.09/BOE in the prior quarter, due to production curtailments on our lower operating cost Marcellus properties along with seasonal well servicing and higher repairs and maintenance costs. Based on continued production curtailments in the Marcellus throughout the fourth quarter, we are reverting to our original 2014 operating costs guidance of $10.25/BOE from $10.10/BOE.

Although oil prices declined significantly during the quarter, we continue to maintain a strong balance sheet and financial flexibility. During the quarter, we closed a US$200 million private placement of 3.79%, 10 year average life senior notes and used the proceeds to repay outstanding bank debt. At September 30, 2014 only 5% of our $1 billion credit facility was drawn and our trailing 12 month debt to funds flow ratio was 1.3x. We also have a strong hedge position in place with approximately 64% of our anticipated remaining 2014 crude oil production hedged at a price of $95.29, and approximately 38% of our anticipated 2015 crude oil production hedged at $93.68.

RESULTS OF OPERATIONS

Production

Production levels were maintained in the third quarter with production of 104,035 BOE/day despite production curtailments that averaged 3,000-4,000 BOE/day over the quarter due to decreased natural gas prices and pipeline maintenance in the Marcellus. Our Fort Berthold crude oil production grew by 6% from the prior quarter with our ongoing development program more than fully offsetting the decline in other crude oil assets.

Compared to the third quarter of 2013, production increased 19% or 16,306 BOE/day. Natural gas volumes grew by approximately 30% due to our ongoing development activity in the Marcellus combined with the fourth quarter 2013 acquisition of additional working interests in our existing Marcellus properties. Over the same period, our crude oil volumes increased by approximately 4% due to growth in our Fort Berthold production volumes.

Our production mix was unchanged from the previous quarter, with natural gas being 58% of production and crude oil and natural gas liquids making up 42% of production.

Average daily production volumes for the three and nine months ended September 30, 2014 and 2013 are outlined below:

	Three months ended September 30,			Nine months ended September 30,		
Average Daily Production Volumes	**2014**	**2013**	**% Change**	**2014**	**2013**	**% Change**
Crude oil (bbls/day)	40,332	38,883	4%	39,328	38,426	2%
Natural gas liquids (bbls/day)	3,869	2,985	30%	3,591	3,357	7%
Natural gas (Mcf/day)	359,007	275,164	30%	356,288	279,212	28%
Total daily sales (BOE/day)	104,035	87,729	19%	102,300	88,318	16%

Based on our year to date performance, we have revised our 2014 annual average production guidance to 102,000-104,000 BOE/day from 100,000-104,000 BOE/day. The lower end of the guidance range assumes ongoing production curtailments in the Marcellus throughout the fourth quarter. This guidance also includes the impact of the September 30, 2014 non-core asset disposition of 1,900 BOE/day and the divestment of non-core gas weighted properties with production of approximately 1,200 BOE/day in the fourth quarter.

Our crude oil and natural gas liquids production has been strong in October. We have just finished drilling and completing a five well pad in North Dakota that we expect to have tied-in by early November. We expect our crude oil and natural gas liquids production to increase to approximately 47,000 BOE/day for the fourth quarter and continue to expect average annual crude oil and natural gas liquids production to grow by 5% from 2013 to average 44,000 BOE/day.

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, 2014 and 2013 and quarterly average prices from the third quarter of 2014 to the third quarter of 2013.

	Nine months ended September 30,						
Pricing (average for the period)	**2014**	**2013**	**Q3 2014**	**Q2 2014**	**Q1 2014**	**Q4 2013**	**Q3 2013**
Benchmarks							
WTI crude oil (US$/bbl)	$ 99.61	$ 98.14	$ 97.17	$ 102.99	$ 98.68	$ 97.46	$ 105.82
AECO natural gas – monthly index (CDN$/Mcf)	4.55	3.16	4.22	4.68	4.76	3.16	2.82
AECO natural gas – daily index (CDN$/Mcf)	4.81	3.05	4.02	4.69	5.71	3.53	2.43
NYMEX natural gas – last day (US$/Mcf)	4.55	3.67	4.06	4.67	4.94	3.60	3.58
US/CDN exchange rate	1.09	1.02	1.09	1.09	1.10	1.05	1.04
Enerplus selling price[1]							
Crude oil (CDN$/ bbl)	$ 90.91	$ 86.05	$ 86.49	$ 94.90	$ 91.48	$ 77.77	$ 96.30
Natural gas liquids (CDN$/ bbl)	53.01	51.48	44.85	49.98	66.30	54.26	49.88
Natural gas (CDN$/ Mcf)	4.04	3.26	3.22	4.02	4.93	3.26	2.96
Average differentials							
MSW Edmonton – WTI (US$/bbl)	$ (7.44)	$ (5.11)	$ (7.93)	$ (6.13)	$ (8.25)	$ (14.93)	$ (4.72)
WCS Hardisty – WTI (US$/bbl)	(21.12)	(22.86)	(20.18)	(20.04)	(23.13)	(32.20)	(17.48)
Brent Futures (ICE) – WTI (US$/bbl)	7.40	10.40	6.25	6.75	9.19	11.86	3.83
AECO monthly – NYMEX (US$/Mcf)	(0.40)	(0.62)	(0.18)	(0.38)	(0.63)	(0.60)	(0.86)
Enerplus realized differentials[1]							
Canada crude oil – WTI (US$/bbl)	$ (20.45)	$ (19.96)	$ (21.78)	$ (17.80)	$ (20.70)	$ (30.73)	$ (15.18)
Canada natural gas – NYMEX (US$/Mcf)	(0.54)	(0.77)	(0.55)	(0.71)	(0.31)	(0.63)	(1.06)
Bakken crude oil – WTI (US$/bbl)	(13.78)	(8.84)	(14.72)	(14.55)	(11.85)	(17.47)	(11.41)
Marcellus natural gas – NYMEX (US$/Mcf)	(1.38)	(0.25)	(1.72)	(1.50)	(0.88)	(0.50)	(0.52)

(1) Net of oil and gas transportation costs, but before the effects of royalties and commodity derivative instruments.

Crude Oil and Natural Gas Liquids

Our crude oil selling price decreased 9% from the prior quarter as a result of lower benchmark prices and widening differentials. WTI crude oil averaged US$97.17/bbl during the third quarter, down almost US$6.00/bbl from the previous period. Global prices declined steadily due to a combination of seasonal refinery turnarounds reducing demand and higher than anticipated global oil production, primarily in North America and Libya. WTI exited September at US$91.16/bbl and continued to weaken in the fourth quarter.

Light sweet crude oil differentials in Canada weakened considerably during the third quarter with mixed sweet blend (MSW) differentials averaging US$7.93/bbl below WTI as a result of continued apportionment on the Canadian pipeline systems decreasing takeaway capacity. The market continues to await the start of the Line 9 pipeline reversal from Sarnia, Ontario to Montreal, Quebec, which is now delayed until early 2015. Once operational, this reversal will provide access to refineries in Eastern Canada and may provide support for light sweet crude prices. In the US, delays in the startup of the Pony Express pipeline from Guernsey, Wyoming to Cushing, Oklahoma continued to restrict takeaway capacity and negatively impact our realized Bakken differentials in the field, which averaged US$14.72/bbl below WTI for the quarter. Western Canadian Select (WCS) heavy oil differentials remained steady at US$20.18/bbl below WTI but began to strengthen near the end of the quarter as the Flanagan South pipeline project from Pontiac, Illinois to Cushing, Oklahoma began purchasing line fill prior to start-up in the fourth quarter.

Natural Gas

Our selling price decreased 20% compared to the second quarter as a result of lower benchmark prices and widening differentials in the Marcellus region. U.S. natural gas prices continued to fall throughout the third quarter as a result of cooler than average summer weather. This led to significantly higher than expected storage injections across most regions and contributed to NYMEX prices falling by over US$0.60/Mcf, averaging US$4.06/Mcf in the third quarter.

In Canada, the AECO differential to NYMEX narrowed to US$0.18/Mcf below NYMEX during the third quarter, compared to US$0.38/Mcf in the second quarter, given the slower pace of storage refill in western Canada. We continue to maintain a balanced mix of AECO basis, month and day index price exposures in our Canadian gas portfolio, with our index exposure split almost evenly between month and day AECO indices.

Natural gas prices in the Marcellus continued to trade at a significant discount to NYMEX, as Marcellus and Utica production continued to outpace growth in pipeline takeaway capacity. Our production is priced primarily off of northeast Pennsylvania and Dominion South Point prices. Scheduled maintenance across a number of interstate pipelines resulted in volatility of spot prices throughout northeast Pennsylvania, with spot prices in the region averaging approximately US$2.00/Mcf below NYMEX for the quarter. With approximately 55% of our Marcellus production during the quarter exposed to spot prices in northeast Pennsylvania and approximately 36% exposed to Dominion South Point, we realized a Marcellus price differential of US$1.72/Mcf below NYMEX. We continue to expect wide differentials in the Marcellus for the remainder of the year, although new pipeline capacity coming on-stream on November 1, 2014 may provide some relief.

Foreign Exchange

The majority of our oil and 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. After regaining some ground in the second quarter, the Canadian dollar weakened by nearly 5% in the third quarter and exited September near year to date lows. During the third quarter, we continued to enter into foreign exchange costless collars on our oil and gas sales to hedge a floor exchange rate on a portion of our U.S. dollar denominated oil and gas sales and to participate in some upside potential in the event the Canadian dollar continues to weaken.

As of October 22, 2014 we have US$26 million per month hedged for the remainder of 2014 at an average USD/CDN floor of 1.1064, ceiling of 1.1500 and conditional ceiling of 1.1212. For 2015, we have US$24 million per month hedged at an average USD/CDN floor of 1.1088, ceiling of 1.1845 and conditional ceiling of 1.1263. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional ceiling is used to determine the settlement amount. During the third quarter, we recorded cash gains of $0.6 million and non-cash mark-to-market losses of $8.7 million on these contracts.

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. During the third quarter and fourth quarter to date we continued to add risk management positions for both crude oil and natural gas. With the decline in crude oil prices we bought back the upside on a portion of our previously swapped crude oil volumes through costless upside participation collars. With respect to natural gas, we entered into additional swap positions for 2015 and 2016 to add more downside protection.

As of October 22, 2014, we have swapped approximately 64% of our forecasted net crude oil production for the remainder of 2014 at an average price of US$95.29/bbl. For the first and second half of 2015, we have swapped approximately 50% and 26%, respectively, of our forecasted net crude oil production at an average price of US$93.58/bbl, and US$93.86/bbl, respectively. In relation to a portion of the volumes swapped we have purchased call options to participate in price upside above US$94.00/bbl and sold put options at an average strike price of US$63.00/bbl, offsetting the call premium. We also have WCS and MSW differential swap positions to manage our exposure to Canadian crude oil differentials. We expect these contracts to protect a significant portion of our funds flow in the near term.

As of October 22, 2014, we have downside protection on approximately 49% and 28% of our forecasted net natural gas production after royalties for the remainder of 2014 and full year 2015, respectively, consisting of a combination of NYMEX swaps, NYMEX collars and AECO swaps.

The following is a summary of our financial contracts in place at October 22, 2014 expressed as a percentage of our anticipated net production volumes:

	WTI Crude Oil (US$/bbl)[1]			AECO Natural Gas (CDN$/Mcf)[1]	NYMEX Natural Gas (US$/Mcf)[1]				
	Oct 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Oct 1, 2014 – Dec 31, 2014	Oct 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Mar 31, 2015	Apr 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Jan 1, 2016 – Dec 31, 2016
Downside Protection Swaps									
Sold Swaps	$ 95.29	$ 93.58	$ 93.86	$ 4.25	$ 4.14	$ 4.25	$ 4.25	$ 4.16	$ 4.03
%	64%	50%	26%	10%	28%	29%	29%	22%	4%
Downside Protection Collars									
Purchased Puts	–	–	–	–	$ 4.30	$ 4.53	–	–	–
%	–	–	–	–	11%	11%	–	–	–
Sold Calls	–	–	–	–	$ 5.08	$ 5.53	–	–	–
%	–	–	–	–	11%	11%	–	–	–
Upside Participation Collars									
Sold Puts	–	$ 63.00	$ 63.00	–	$ 3.23	$ 3.25	$ 3.25	$ 3.25	–
%	–	6%	6%	–	9%	2%	2%	2%	–
Sold Calls	–	–	–	–	$ 5.00	$ 5.00	$ 5.00	$ 5.00	–
%	–	–	–	–	9%	2%	2%	2%	–
Purchased Calls	–	$ 94.00	$ 94.00	–	$ 4.17	$ 4.29	$ 4.29	$ 4.29	–
%	–	6%	6%	–	9%	2%	2%	2%	–

(1) Based on weighted average price (before premiums), assumed average annual production of 102,000 – 104,000 BOE/day for 2014 and 2015, less royalties and production taxes of 23% in aggregate.

ACCOUNTING FOR PRICE RISK MANAGEMENT

Risk Management Gains/(Losses) ($ millions)	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Cash gains/(losses):				
Crude oil	$ (4.2)	$ (12.9)	$ (36.2)	$ 9.0
Natural gas	1.7	2.3	(6.2)	1.1
Total cash gains/(losses)	$ (2.5)	$ (10.6)	$ (42.4)	$ 10.1
Non-cash gains/(losses):				
Change in fair value – crude oil	$ 82.9	$ (45.6)	$ 48.7	$ (66.5)
Change in fair value – natural gas	10.9	0.5	8.3	4.3
Total non-cash gains/(losses)	$ 93.8	$ (45.1)	$ 57.0	$ (62.2)
Total gains/(losses)	$ 91.3	$ (55.7)	$ 14.6	$ (52.1)

(Per BOE)	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Total cash gains/(losses)	$ (0.26)	$ (1.30)	$ (1.52)	$ 0.42
Total non-cash gains/(losses)	9.80	(5.60)	2.04	(2.58)
Total gains/(losses)	$ 9.54	$ (6.90)	$ 0.52	$ (2.16)

During the third quarter 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. In comparison, during the third quarter of 2013, we realized cash losses of $12.8 million on our crude oil contracts and cash gains of $2.3 million on our natural gas contracts. The cash losses realized in 2014 and 2013 were a result of crude oil prices rising above our fixed price swap positions, while cash gains were due to natural gas contracts that provided floor protection above market prices.

As the forward markets for crude oil and natural gas fluctuate, as new contracts are executed, and as existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the third quarter of 2014, the fair value of our crude oil and natural gas contracts represented net gain positions of $33.8 million and $8.6 million, respectively. For the three and nine months ended September 30, 2014 the change in the fair value of our crude oil contracts represented gains of $82.9 million and $48.7 million, respectively, while the change in fair value of our natural gas contracts represented gains of $10.9 million and $8.3 million, respectively.

Revenues

($ millions)	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Oil and natural gas sales	$ 456.2	$ 441.5	$ 1,455.8	$ 1,219.8
Royalties	(77.9)	(76.1)	(254.8)	(199.7)
Oil and natural gas sales, net of royalties	$ 378.3	$ 365.4	$ 1,201.0	$ 1,020.1

Oil and natural gas sales were $456.2 million in the third quarter of 2014, an increase of 3% or $14.7 million compared to the same period in 2013. For the nine months ended September 30, 2014, oil and natural gas sales were $1,455.8 million, an increase of 19% or $236.0 million compared to the same period a year ago. The increase in revenues was driven primarily by year over year production growth. Although crude oil and natural gas liquids selling prices were lower during the quarter compared to the same period in 2013, improved pricing in the first half of the year led to an overall improvement in realized prices year to date.

Royalties and Production Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Royalties	$ 77.9	$ 76.1	$ 254.8	$ 199.7
Production taxes	21.3	20.0	61.1	52.5
Royalties and production taxes	$ 99.2	$ 96.1	$ 315.9	$ 252.2
As a % of oil and natural gas sales, net of transportation	22%	22%	22%	21%

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2014	2013	2014	2013
Royalties	$ 8.14	$ 9.43	$ 9.12	$ 8.27
Production taxes	2.22	2.48	2.19	2.19
Royalties and production taxes	$ 10.36	$ 11.91	$ 11.31	$ 10.46
As a % of oil and natural gas sales, net of transportation	22%	22%	22%	21%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. During the three and nine months ended September 30, 2014 royalties and production taxes increased to $99.2 million and $315.9 million, respectively, from $96.1 million and $252.2 million for the same periods in 2013. This upward trend is primarily due to increased production from higher royalty rate U.S. properties. As a percentage of oil and gas sales, net of transportation costs, royalties and production taxes averaged 22% for the three and nine months ended September 30, 2014 compared to 22% and 21%, respectively, for the same periods in 2013.

We continue to expect an average royalty and production tax rate of 23% in 2014.

Operating Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
Operating Expenses	$ 102.1	$ 85.5	$ 286.7	$ 252.3
Per BOE	$ 10.67	$ 10.60	$ 10.27	$ 10.46

Operating expenses for the three and nine months ended September 30, 2014 were $102.1 million or $10.67/BOE and $286.7 million or $10.27/BOE, respectively. In comparison, operating costs were $85.5 million or $10.60/BOE and $252.3 million or $10.46/BOE for the same periods in 2013.

The production curtailments at our lower operating cost Marcellus properties negatively impacted operating costs on a per BOE basis during the quarter. Seasonal well servicing and higher repairs and maintenance costs also increased our operating costs in the third quarter.

Based on ongoing production curtailments in the Marcellus in the fourth quarter we have revised our 2014 guidance to $10.25/BOE from $10.10/BOE, consistent with our original guidance for 2014.

Transportation Costs

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
Transportation costs	$ 14.7	$ 8.8	$ 40.9	$ 22.3
Per BOE	$ 1.53	$ 1.09	$ 1.46	$ 0.92

Transportation costs for the three and nine months ended September 30, 2014 were $14.7 million or $1.53/BOE and $40.9 million or $1.46/BOE, respectively, compared to $8.8 million or $1.09/BOE and $22.3 million or $0.92/BOE for the same periods in 2013. The increase from the prior year was related to higher U.S. production as well as costs associated with securing U.S. pipeline capacity.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and nine months ended September 30, 2014 and 2013. The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A. Certain prior period amounts have been reclassified to conform with current period presentation.

	Three months ended September 30, 2014		
Netbacks by Property Type	**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[2]	$ 80.15	$ 3.32	$ 46.13
Royalties and production taxes	(20.73)	(0.40)	(10.36)
Cash operating costs	(13.13)	(1.46)	(10.67)
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

	Three months ended September 30, 2013		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	43,670 BOE/day	264,354 Mcfe/day	87,729 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 88.44	$ 3.18	$ 53.61
Royalties and production taxes	(20.74)	(0.53)	(11.91)
Cash operating costs	(12.26)	(1.49)	(10.58)
Netback before hedging	$ 55.44	$ 1.16	$ 31.12
Cash gains/(losses)	(3.20)	0.10	(1.30)
Netback after hedging	$ 52.24	$ 1.26	$ 29.82
Netback before hedging ($ millions)	$ 222.7	$ 28.5	$ 251.2
Netback after hedging ($ millions)	$ 209.9	$ 30.8	$ 240.6

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[(2)]	$ 84.18	$ 4.17	$ 50.66
Royalties and production taxes	(21.08)	(0.64)	(11.31)
Cash operating costs	(12.78)	(1.39)	(10.28)
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

Netbacks by Property Type	Nine months ended September 30, 2013 Crude Oil	Natural Gas	Total
Average Daily Production	43,447 BOE/day	269,226 Mcfe/day	88,318 BOE/day
Netback[(1)] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[(2)]	$ 78.41	$ 3.64	$ 49.67
Royalties and production taxes	(18.37)	(0.47)	(10.46)
Cash operating costs	(12.25)	(1.47)	(10.52)
Netback before hedging	$ 47.79	$ 1.70	$ 28.69
Cash gains/(losses)	0.76	0.02	0.42
Netback after hedging	$ 48.55	$ 1.72	$ 29.11
Netback before hedging ($ millions)	$ 566.8	$ 125.0	$ 691.8
Netback after hedging ($ millions)	$ 575.8	$ 126.1	$ 701.9

(1) See "Non-GAAP Measures" in this MD&A.
(2) Net of transportation costs.

Our crude oil properties accounted for 75% of our corporate netback before hedging for the year to date compared to 82% for the same period in 2013. Crude oil netbacks per BOE before hedging decreased during the three months ended September 30, 2014 compared to the same period in 2013 primarily due to lower realized crude oil prices. For the nine months ended September 30, 2014 average realized crude oil prices were higher than the same period in 2013 which resulted in higher crude oil netbacks before hedging compared to the previous year. Natural gas netbacks per Mcfe before hedging increased for the three and nine months ended compared to the same period last year primarily due to the increase in realized natural gas prices from 2013.

General and Administrative ("G&A") Expenses

Total G&A expenses include cash G&A expenses as well as share-based compensation ("SBC") charges related to our long-term incentive plans ("LTI plans") and our stock option plan. SBC charges are dependent on our share price and can fluctuate from period to period.

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Cash:				
G&A expense[1]	$ 18.9	$ 20.0	$ 58.1	$ 63.5
SBC expense/(recovery)	(5.2)	4.9	12.3	14.1
Non-Cash:				
SBC	3.4	1.7	9.9	7.2
SBC – equity swap loss/(gain)	5.8	(1.5)	(0.1)	(3.8)
Total G&A expenses	$ 22.9	$ 25.1	$ 80.2	$ 81.0

	Three months ended September 30,		Nine months ended September 30,	
(Per BOE)	2014	2013	2014	2013
Cash:				
G&A expense[1]	$ 1.97	$ 2.48	$ 2.08	$ 2.63
SBC expense/(recovery)	(0.54)	0.60	0.44	0.58
Non-Cash:				
SBC	0.36	0.21	0.35	0.30
SBC – equity swap loss/(gain)	0.61	(0.18)	–	(0.16)
Total G&A expenses	$ 2.40	$ 3.11	$ 2.87	$ 3.35

(1) Excluding SBC.

Cash G&A expenses during the third quarter were $18.9 million or $1.97/BOE compared to $20.0 million or $2.48/BOE in the third quarter of 2013. For the nine months ended September 30, 2014 cash G&A expenses were $58.1 million or $2.08/BOE compared to $63.5 million or $2.63/BOE for the same period in 2013. The decrease during 2014 was partially due to one-time charges recorded in the prior year associated with the departure of personnel, while higher production volumes in 2014 also contributed to a decrease in our reported G&A on a per BOE basis. We are maintaining our cash G&A guidance at $2.30/BOE for the year.

Our share price decreased by 21% during the quarter, reducing our cash SBC expense and resulting in a recovery of $5.2 million or $0.54/BOE compared to a charge of $4.9 million or $0.60/BOE during the third quarter of 2013. For the nine months ended September 30, 2014 cash SBC expense was $12.3 million or $0.44/BOE compared to $14.1 million or $0.58/BOE for the same period in the prior year.

We have hedged a portion of the outstanding cash settled units under our LTI plans at an average price of $14.92/share. As a result of the decrease in our share price we recorded a non-cash mark-to-market loss of $5.8 million for the quarter and a gain of $0.1 million for the nine months ended September 30, 2014.

Based on our September 30, 2014 share price of $21.26 we have revised our 2014 guidance for cash SBC to $0.45/BOE from $0.60/BOE.

Interest Expense

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Interest on senior notes and bank facility	$ 14.9	$ 14.7	$ 45.5	$ 43.1
Non-cash interest expense	0.3	0.4	1.4	1.2
Total interest expense	$ 15.2	$ 15.1	$ 46.9	$ 44.3

For the three and nine months ended September 30, 2014 we recorded total interest expense of $15.2 million and $46.9 million, respectively, compared to $15.1 million and $44.3 million in the same periods in 2013.

Interest expense increased marginally for the three and nine months ended September 30, 2014 compared to the same periods in 2013 mainly due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments.

At September 30, 2014, after including our underlying derivatives, approximately 95% of our debt was based on fixed interest rates and 5% on floating interest rates, with weighted average interest rates of 5.28% and 2.92%, respectively. The percentage of fixed rate debt has increased from prior periods as we closed our US$200.0 million senior notes offering on September 3, 2014 and used the proceeds to pay down bank debt.

Foreign Exchange

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Realized loss/(gain)	$ (2.6)	$ 0.1	$ 14.0	$ 17.7
Unrealized loss/(gain)	33.1	(2.6)	10.7	(13.7)
Total foreign exchange loss/(gain)	$ 30.5	$ (2.5)	$ 24.7	$ 4.0

We recorded a net foreign exchange loss of $30.5 million during the third quarter and a loss of $24.7 million year to date, compared to a net gain of $2.5 million and a net loss of $4.0 million, respectively, during the same periods in 2013.

Realized gains during the quarter resulted from foreign exchange gains on day-to-day transactions denominated in foreign currencies. Unrealized foreign exchange losses related to the translation of our U.S. dollar denominated debt and working capital.

Capital Investment and Dispositions

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Capital spending	$ 207.8	$ 145.8	$ 630.0	$ 458.4
Office capital	1.4	1.2	3.0	3.4
Sub-total	$ 209.2	$ 147.0	$ 633.0	$ 461.8
Property and land acquisitions	$ 4.0	$ 15.8	$ 17.2	$ 71.5
Property dispositions	(68.9)	(124.5)	(185.6)	(197.1)
Sub-total	$ (64.9)	$ (108.7)	$ (168.4)	$ (125.6)
Total net capital investment	$ 144.3	$ 38.3	$ 464.6	$ 336.2

Capital spending for the third quarter totaled $207.8 million compared to $145.8 million during the same period in 2013. We continue to focus our spending on our core development areas with 64% directed towards crude oil development. Crude oil spending for the quarter included $95.7 million at Fort Berthold and $37.0 million on our Canadian waterflood properties. Natural gas spending included $56.6 million in the Marcellus and $16.1 million on our Deep Basin assets.

During the quarter we had minor property and land acquisitions totaling $4.0 million, of which $2.0 million related to undeveloped land acquisitions in our Deep Basin properties and $2.0 million related to additional land interests around our existing Marcellus acreage. In the third quarter of 2013 we spent $15.8 million which included $6.4 million for additional land interests in the Deep Basin, $7.5 million in Fort Berthold and $1.9 million in the Marcellus.

On September 30, 2014, we divested of $69.0 million of non-core natural gas properties in the Deep Basin area with production of approximately 1,900 BOE/day. During the quarter, we also entered into an agreement to sell additional non-core Canadian natural gas properties with production of approximately 1,200 BOE/day for net proceeds of approximately $22.0 million. This transaction closed in early November. Combined, we expect to realize approximately $30,000 per flowing barrel on these non-core gas divestments.

Property dispositions during the third quarter of 2013 totaled $124.5 million which included non-core Canadian properties primarily in Saskatchewan and Alberta for proceeds of $89.3 million as well as certain facilities in Fort Berthold for proceeds of $35.2 million.

Our successful non-core divestments have allowed us to increase our capital spending program and redeploy a portion of the proceeds to accelerate our 2015 capital spending programs in Fort Berthold and the Wilrich. As a result, we have increased our capital spending guidance for the year to $830 million from $800 million.

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

	Three months ended September 30,		Nine months ended September 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
DDA&A expense	$ 159.7	$ 163.3	$ 440.5	$ 470.1
Per BOE	$ 16.68	$ 20.24	$ 15.77	$ 19.50

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, 2014 DDA&A decreased to $159.7 million and $440.5 million, respectively, compared to $163.3 million and $470.1 million during the same periods in 2013. The decrease was primarily due to significant reserve additions for the year ended December 31, 2013 that lowered our depletion rate for 2014.

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 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 $286.7 million at September 30, 2014 compared to $291.8 million at December 31, 2013.

Income Taxes

	Three months ended September 30,		Nine months ended September 30,	
($ millions)	2014	2013	2014	2013
Current tax expense	$ –	$ 5.2	$ 11.4	$ 7.9
Deferred tax expense/(recovery)	36.9	(6.6)	74.1	15.6
Total tax expense/(recovery)	$ 36.9	$ (1.4)	$ 85.5	$ 23.5

For the three and nine months ended September 30, 2014, we recorded a total tax expense of $36.9 million and $85.5 million respectively, compared to a $1.4 million tax recovery and a $23.5 million tax expense in the same periods in 2013. The increase in our total tax expense is due to higher net income in 2014.

Our current tax is comprised mainly of Alternative Minimum Tax ("AMT") payable with respect to our U.S. subsidiary. We expect to recover AMT in future years as an offset to regular U.S. income taxes otherwise payable. Given the decrease in commodity prices and resulting decrease in forecasted net income for the year, a current tax accrual was not needed during the third quarter. Based on current commodity prices and assuming no acquisitions and divestiture activity, we expect to pay U.S. cash taxes of approximately 2% of our U.S. funds flow in 2014, and approximately 3% – 5% from 2015 to 2018. We currently do not expect to pay material cash taxes in Canada until after 2018.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

The following table provides a geographical split of key operating and financial results for the three and nine months ended September 30, 2014 and 2013.

	Three months ended September 30, 2014			Three months ended September 30, 2013		
(millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	16,837	23,495	40,332	17,246	21,637	38,883
Natural gas liquids (bbls/day)	2,578	1,291	3,869	2,265	720	2,985
Natural gas (Mcf/day)	154,855	204,152	359,007	174,169	100,995	275,164
Total average daily production (BOE/day)	45,224	58,811	104,035	48,539	39,190	87,729
Pricing[2]						
Crude oil (per bbl)	$ 82.11	$ 89.63	$ 86.49	$ 94.12	$ 98.04	$ 96.30
Natural gas liquids (per bbl)	46.28	42.01	44.85	58.64	22.31	49.88
Natural gas (per Mcf)	3.82	2.77	3.22	2.62	3.55	2.96
Capital Expenditures						
Capital spending	$ 55.2	$ 152.6	$ 207.8	$ 57.0	$ 88.8	$ 145.8
Acquisitions	2.0	2.0	3.9	6.4	9.4	15.8
Dispositions	(68.9)	0.0	(68.9)	(89.3)	(35.2)	(124.5)
Netback Before Hedging						
Oil and natural gas sales	$ 199.3	$ 256.9	$ 456.2	$ 209.6	$ 231.9	$ 441.5
Royalties	(27.1)	(50.8)	(77.9)	(31.6)	(44.5)	(76.1)
Cash operating expense	(64.7)	(37.3)	(102.0)	(62.2)	(23.2)	(85.4)
Production taxes	(2.5)	(18.8)	(21.3)	(1.4)	(18.6)	(20.0)
Transportation expense	(6.2)	(8.5)	(14.7)	(5.5)	(3.3)	(8.8)
Netback before hedging	$ 98.8	$ 141.5	$ 240.3	$ 108.9	$ 142.3	$ 251.2
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (91.3)	$ –	$ (91.3)	$ 55.7	$ –	$ 55.7
General and administrative expense	19.8	3.1	22.9	20.7	4.4	25.1
Current income tax expense/(recovery)	(0.1)	0.1	–	(0.3)	5.5	5.2

(1) Company interest volumes.
(2) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.

(millions, except per unit amounts)	Nine months ended September 30, 2014 Canada	U.S.	Total	Nine months ended September 30, 2013 Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	16,867	22,461	39,328	18,253	20,173	38,426
Natural gas liquids (bbls/day)	2,531	1,060	3,591	2,782	575	3,357
Natural gas (Mcf/day)	154,306	201,982	356,288	179,503	99,709	279,212
Total average daily production (BOE/day)	45,116	57,184	102,300	50,952	37,366	88,318
Pricing(2)						
Crude oil (per bbl)	$ 87.05	$ 93.81	$ 90.91	$ 80.02	$ 91.50	$ 86.05
Natural gas liquids (per bbl)	57.37	42.60	53.01	56.59	26.77	51.48
Natural gas (per Mcf)	4.41	3.76	4.04	2.97	3.78	3.26
Capital Expenditures						
Capital spending	$ 243.2	$ 386.8	$ 630.0	$ 184.4	$ 274.0	$ 458.4
Acquisitions	2.0	15.2	17.2	44.0	27.5	71.5
Dispositions	(136.6)	(49.0)	(185.6)	(154.5)	(42.6)	(197.1)
Netback Before Hedging						
Oil and natural gas sales	$ 645.3	$ 810.5	$ 1,455.8	$ 606.7	$ 613.1	$ 1,219.8
Royalties	(96.2)	(158.6)	(254.8)	(82.1)	(117.6)	(199.7)
Cash operating expense	(189.1)	(97.8)	(286.9)	(193.6)	(60.0)	(253.6)
Production taxes	(6.4)	(54.7)	(61.1)	(7.8)	(44.7)	(52.5)
Transportation expense	(17.9)	(23.0)	(40.9)	(17.3)	(4.9)	(22.2)
Netback before hedging	$ 335.7	$ 476.4	$ 812.1	$ 305.9	$ 385.9	$ 691.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ (14.6)	$ –	$ (14.6)	$ 52.1	$ –	$ 52.1
General and administrative expense	65.7	14.5	80.2	69.4	11.6	81.0
Current income tax expense/(recovery)	(0.5)	11.9	11.4	(0.3)	8.2	7.9

(1) Company interest volumes.
(2) Net of transportation costs, but before royalties and the effects of commodity derivative instruments.

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
2014				
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	$ 1,200.9	$ 147.4	$ 0.73	$ 0.70
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	$ 1,352.5	$ 48.0	$ 0.24	$ 0.24
2012				
Fourth Quarter	$ 310.2	$ 34.6	$ 0.18	$ 0.18
Third Quarter	279.3	(88.6)	(0.45)	(0.45)
Second Quarter	274.3	(41.9)	(0.21)	(0.21)
First Quarter	289.5	(174.8)	(0.92)	(0.92)
Total	$ 1,153.3	$ (270.7)	$ (1.38)	$ (1.38)

Oil and gas sales, net of royalties, increased in 2014 compared to 2013 primarily due to increased production and higher realized commodity prices. In the third quarter of 2014 lower realized commodity prices resulted in lower oil and gas sales for the quarter. Throughout 2013 and 2012 oil and gas sales, net of royalties, generally increased with higher production although volatile commodity prices caused some fluctuations.

Net income for 2014 benefited from higher production and generally higher realized prices offset by fluctuating risk management costs and foreign exchange gains and losses. Net income for 2013 and 2012 was impacted by fluctuating risk management costs, asset impairment charges and gains on marketable security divestments.

LIQUIDITY AND CAPITAL RESOURCES

We continued to maintain a strong balance sheet and ample liquidity through the third quarter. At September 30, 2014 we had a conservative trailing 12 month debt to cash flow ratio of 1.3x. On September 3, 2014 we closed a private placement of US$200.0 million of senior unsecured notes, with a twelve year amortizing term, a ten year average life and a fixed interest rate of 3.79%. The proceeds were used to repay our short-term, floating interest rate bank debt, and as a result we had $942.5 million of undrawn capacity on our $1 billion credit facility at quarter end.

Our adjusted payout ratio, calculated as dividends (net of SDP proceeds) plus capital and office spending, divided by funds flow, increased to 122% and 120% for the three and nine months ended September 30, 2014, respectively, compared to 97% and 103% for the same periods in 2013. Although funds flow increased by 8% and 13% for the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013, we saw a proportionately larger increase in our capital spending program and a decrease in our SDP participation over the same period. Despite the increase in adjusted payout ratio, the health of our balance sheet has been maintained in part due to the success of our non-core asset divestment program.

We continue to hedge a portion of our commodity price risk and expect our risk management program to provide funds flow protection in the near term. At September 30, 2014 we had approximately 64% of our anticipated remaining 2014 crude oil production hedged at a price of $95.29, and approximately 38% of our anticipated 2015 oil production hedged at $93.68.

Total debt net of cash at September 30, 2014 was $1,091.1 million compared to $1,022.3 million at December 31, 2013. Total debt was comprised of $57.5 million of bank indebtedness and $1,035.7 million of senior notes, less $2.1 million in cash. A significant portion of our senior notes are denominated in U.S. dollars and given the weakening Canadian dollar our total reported debt has increased. Our working capital deficiency, excluding cash and current deferred financial and tax assets and credits, increased slightly during the quarter to $252.5 million from $251.2 million in the second quarter. We expect to finance our working capital deficit through funds flow and our bank credit facility.

Our key leverage ratios are detailed below:

Financial Leverage and Coverage	September 30, 2014	December 31, 2013
Long-term debt to funds flow (trailing 12-month)(1)	1.3 x	1.4 x
Funds flow to interest expense (trailing 12-month)(2)	14.0 x	13.3 x
Long-term debt to long-term debt plus equity(1)	35%	35%

(1) Long-term debt is measured net of cash and includes the current portion of the senior notes.
(2) Interest expense excluding non-cash items.

At September 30, 2014 we were in compliance with all covenants under our bank credit facility and 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 and on the EDGAR website at www.sec.gov.

Dividends

($ millions, except per share amounts)	Three months ended September 30, 2014	2013	Nine months ended September 30, 2014	2013
Cash dividends	$ 51.1	$ 42.4	$ 143.8	$ 128.7
Stock dividend plan	4.3	12.0	21.8	33.5
Total dividends to shareholders	$ 55.4	$ 54.4	$ 165.6	$ 162.2
Per weighted average share (Basic)	$ 0.27	$ 0.27	$ 0.81	$ 0.81

During the three and nine months ended September 30, 2014 we maintained our monthly $0.09/share dividend, resulting in dividends to shareholders of $55.4 million ($0.27/share) and $165.6 million ($0.81/share), respectively, compared to $54.5 million ($0.27/share) and $162.2 million ($0.81/share) for the same periods in 2013. For the first nine months of 2014, dividend payments including SDP amounted to 26% of our funds flow of $646.5 million. We continue to monitor our dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions and do not anticipate any changes to our dividend at this time.

Effective September 19, 2014 the Board of Directors elected to suspend the SDP in an effort to eliminate the dilution associated with the issuance of shares through the plan. Effective with the October 2014 dividend, all dividends will be paid in cash on or about the 15th day of the month, approximately five days earlier than previously. All record dates and ex-dividend dates will also be adjusted accordingly with future record dates being on or about the last business day of the previous calendar month.

Commitments

During the third quarter we acquired additional transportation commitments for 11.1 MMcf/day on various pipelines in the Marcellus region. These contracts relate to the additional working interest acquisition at the end of 2013 and have various terms extending out to 2020, 2028 and 2033 and comprise a total commitment of approximately US$54.3 million.

Shareholders' Capital

	Nine months ended September 30, 2014	2013
Share capital ($ millions)	$ 3,115.5	$ 3,046.1
Common shares outstanding (thousands)	205,423	201,873
Weighted average shares outstanding – basic (thousands)	204,174	200,002
Weighted average shares outstanding – diluted (thousands)	207,970	200,415

During the third quarter of 2014, a total of 655,000 shares (2013 – 1,605,000) and $12.2 million of additional equity (2013 – $26.9 million) was issued pursuant to the SDP and the stock option plan. For the nine months ended September 30, 2014, a total of 2,665,000 shares (2013 – 3,189,000) and $48.9 million of additional equity (2013 – $48.4 million) was issued pursuant to the SDP and the stock option plan.

At September 30, 2014 we had 205,423,000 shares outstanding (2013 – 201,874,000) and at November 6, 2014 we had 205,434,022 shares outstanding.

2014 GUIDANCE

A summary of our 2014 guidance is below.

Summary of 2014 Expectations	Target
Average annual production	102,000 – 104,000 BOE/day (from 100,000 – 104,000 BOE/day)
Production mix (volumes)	44,000 BOE/day crude oil and natural gas liquids 58,000-60,000 BOE/day natural gas (from 56,000-60,000 BOE/day)
Capital spending	$830 million (from $800 million)
Average royalty rate (% of gross sales, net of transportation)	23%
Operating costs	$10.25/BOE (from $10.10/BOE)
Cash G&A expenses	$2.30/BOE
Cash share-based compensation expenses	$0.45/BOE (from $0.60/BOE)
U.S. Cash taxes (% of U.S. funds flow)	2% (from 3%-5%)

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 Issuers' Annual and Interim Filings. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of Enerplus Corporation have concluded that, as at September 30, 2014, 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, 2014 and ending September 30, 2014 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 2014 and 2015 average production volumes and the anticipated production mix; the proportion of our anticipated oil and gas production that is hedged; the results from our drilling program and the timing of related production; future oil and natural gas prices and differentials and our commodity risk management programs; 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 costs; capital spending levels in 2014 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 U.S. cash taxes; deferred income taxes, our tax pools and the time at which we may pay Canadian cash taxes and regular U.S. 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; the amount and timing of future cash dividends that we may pay to our shareholders; and future dispositions, including expected proceeds therefrom and production volumes associated therewith.*

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; 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; commodity price and cost assumptions; 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. We believe the material factors, expectations and assumptions reflected in the forward-looking information are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct.*

The forward-looking information included in this MD&A is not a guarantee of future performance and should not be unduly relied upon. Such information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information including, without limitation: changes in commodity prices; changes in realized prices of Enerplus' products; changes in the demand for or supply of our products; unanticipated operating results, results from our capital spending activities or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in our capital plans or by third party operators of our properties; increased debt levels or debt service requirements; inaccurate estimation of our oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners and third party service providers; a failure to complete planned asset dispositions on the terms anticipated or at all; 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 this MD&A and in our other public filings).

The forward-looking information contained in this MD&A speaks only as of the date of this MD&A, and we do not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws.