Q2 2014

enerPLUS

ENERPLUS SECOND QUARTER REPORT
SIX MONTHS ENDED JUNE 30, 2014

SELECTED FINANCIAL RESULTS	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Financial (000's)				
Funds Flow	$ 213,211	$ 204,706	$ 433,723	$ 377,305
Cash and Stock Dividends	55,214	54,009	110,149	107,794
Net Income	39,957	38,467	79,994	22,070
Debt Outstanding – net of cash	1,067,590	1,133,048	1,067,590	1,133,048
Capital Spending	204,427	139,644	422,190	312,591
Property and Land Acquisitions	3,231	51,692	13,200	55,659
Property Dispositions	(525)	71,293	116,700	72,624
Debt to Trailing 12-Month Funds Flow	1.3x	1.6x	1.3x	1.6x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 1.04	$ 1.02	$ 2.13	$ 1.89
Net Income (Basic)	0.20	0.19	0.39	0.11
Weighted Average Number of Shares Outstanding (000's)	204,158	199,825	203,671	199,430
Selected Financial Results per BOE[1][2]				
Oil & Natural Gas Sales[3]	$ 51.93	$ 48.65	$ 53.03	$ 47.68
Royalties and Production Taxes	(11.58)	(9.93)	(11.81)	(9.73)
Commodity Derivative Instruments	(2.60)	1.11	(2.17)	1.29
Operating Costs	(10.12)	(10.55)	(10.07)	(10.48)
General and Administrative	(1.97)	(2.29)	(2.14)	(2.71)
Share-Based Compensation	(1.12)	(0.45)	(0.95)	(0.57)
Interest, Foreign Exchange and Other Expenses	(1.61)	(1.38)	(1.63)	(1.78)
Taxes	(0.40)	(0.18)	(0.63)	(0.18)
Funds Flow	$ 22.53	$ 24.98	$ 23.63	$ 23.52

SELECTED OPERATING RESULTS	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Average Daily Production[2]				
Crude oil (bbls/day)	39,863	38,066	38,817	38,193
NGLs (bbls/day)	3,636	3,497	3,450	3,546
Natural gas (Mcf/day)	362,929	290,841	354,906	281,275
Total (BOE/day)	103,987	90,037	101,418	88,618
% Natural Gas	58%	54%	58%	53%
Average Selling Price[2][3]				
Crude oil (per bbl)	$ 94.90	$ 82.95	$ 93.25	$ 80.74
NGLs (per bbl)	49.98	45.64	57.66	52.16
Natural gas (per Mcf)	4.02	3.70	4.46	3.41
Net Wells drilled	14	10	44	35

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

Average Benchmark Pricing	Three months ended June 30, 2014	2013	Six months ended June 30, 2014	2013
WTI crude oil (US$/bbl)	$ 102.99	$ 94.22	$ 100.84	$ 94.30
AECO – monthly index (CDN$/Mcf)	4.68	3.59	4.72	3.34
AECO – daily index (CDN$/Mcf)	4.69	3.53	5.20	3.37
NYMEX – last day (US$/Mcf)	4.67	4.09	4.80	3.71
USD/CDN exchange rate	1.09	1.02	1.10	1.02

Share Trading Summary For the three months ended June 30, 2014	CDN* – ERF (CDN$)	U.S.** – ERF (US$)
High	$ 26.92	$ 25.24
Low	$ 21.54	$ 19.58
Close	$ 26.89	$ 25.18

* TSX and other Canadian trading data combined.

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

2014 Dividends per Share Payment Month	CDN$	US$(1)
First Quarter Total	$ 0.27	$ 0.24
April	$ 0.09	$ 0.08
May	$ 0.09	$ 0.08
June	$ 0.09	$ 0.08
Second Quarter Total	$ 0.27	$ 0.24
Total Year-to-Date	$ 0.54	$ 0.48

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

PRESIDENT'S MESSAGE

I am pleased to report that Enerplus delivered another quarter of strong operational and financial performance. We achieved record production of 104,000 BOE per day which is the highest level in our 28 year history. We grew production in each of our four core areas. In particular, our North Dakota production grew by 14% from the first quarter of 2014.

Daily production was up 5% quarter over quarter, and 15% higher than the same period one year ago. Liquids production grew by 6% quarter over quarter averaging 43,500 barrels per day driven by the significant growth in light oil from North Dakota. The Marcellus also continued to outperform increasing our total natural gas volumes quarter over quarter.

As a result of the continued operational outperformance, we are increasing our annual average production guidance by 4,000 BOE per day. We now expect to produce between 100,000 BOE per day and 104,000 BOE per day in 2014. We continue to expect to grow our liquids volumes throughout the year and are maintaining our guidance of 44,000 barrels per day in 2014. Natural gas production is also expected to grow ahead of our expectations due to the performance of the Marcellus. It also assumes the sale of 2,500 to 3,500 BOE per day of gas weighted production from non-core properties in Canada that we expect to close in the fourth quarter.

Our capital spending is on track year-to-date. With the strength of our balance sheet and the anticipated proceeds from our non-core divestments we are evaluating opportunities to modestly increase spending in our core areas. At this time, we are maintaining our capital spending guidance at $800 million but plan to review spending levels in the third quarter. We also expect to see an improvement in operating costs and cash general and administrative costs. We are now forecasting operating costs of $10.10 per BOE, down from $10.25 per BOE and cash general and administrative costs of $2.30 per BOE down from our previous guidance of $2.45 per BOE.

During the quarter, the largest share of our capital spending continued to be allocated to Fort Berthold, where we directed almost half of our $204 million investment. Our development activities in this area have significantly increased the value of this asset. As announced on June 18, 2014, our estimate of economic contingent resources has increased by 250% to 136 million BOE. In addition, our drilling inventory increased by 125% and we now estimate approximately 330 net drilling locations, representing 16 years of future drilling at our current two-rig pace. This presentation is available on our website.

Funds flow in the quarter grew by 4% compared to the same period in 2013. Compared to last quarter, our funds flow modestly declined due to a 20% drop in realized natural gas prices. This is despite the growth in production and higher crude oil prices in the quarter. Both AECO and NYMEX gas prices declined and we continued to see pressure on basis differentials in the Marcellus. Although our long-term pricing contracts shielded us somewhat, price differentials in the Marcellus averaged US$1.50 per Mcf below NYMEX for the second quarter. Given the increasing supply outlook in the region, and our growing uncontracted production volumes, we are revising our Marcellus price differential outlook and expect to average a discount of US$1.35 per Mcf to NYMEX for calendar 2014.

With rising crude oil prices, we continued to hedge our future production volumes in order to protect a portion of our funds flow, and support our capital spending plans and dividend. We increased our hedges for 2015 significantly since the last quarter. We have now swapped half of our net oil production after royalties for the first six months of 2015 at an average price of US$93.58 per barrel. For the second half of 2015, we've swapped 26% of our net oil production after royalties at similar prices.

Our financial flexibility remains strong, ending the quarter with a trailing 12-month debt-to-funds flow ratio of 1.3x, unchanged from Q1 2014. We further strengthened our financial position entering into private placement agreements for a US$200 million offering of senior, twelve-year amortizing, unsecured notes at a fixed-rate coupon of 3.79%. We expect to close the offering in early September, and will use the proceeds to pay down our bank debt, replacing short-term, floating interest rate debt with long-term debt at an attractive fixed interest rate.

Production and Capital Spending

	Three months ended June 30, 2014		Six months ended June 30, 2014	
	Average Production Volumes	Capital Spending ($ millions)	Average Production Volumes	Capital Spending ($ millions)
Crude Oil & NGLs (BOE/day)				
Canada	19,660	$ 28	19,390	$ 91
United States	23,839	99	22,877	158
Total Crude Oil & NGLs (BOE/day)	43,499	$ 127	42,267	$ 249
Natural Gas (Mcf/day)				
Canada	156,401	$ 32	154,027	$ 97
United States	206,528	45	200,879	76
Total Natural Gas (Mcf/day)	362,929	$ 77	354,906	$ 173
Company Total (BOE/day)	103,987	$ 204	101,418	$ 422

Net Drilling Activity – for the three months ended June 30, 2014

	Horizontal Wells	Wells Pending Completion/Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Crude Oil				
Canada	1.5	1.1	6.9	–
United States	6.9	6.9	5.1	–
Total Crude Oil	**8.4**	**8.0**	**12.0**	**–**
Natural Gas				
Canada	–	–	1.4	–
United States	5.9	4.6	5.9	–
Total Natural Gas	**5.9**	**4.6**	**7.3**	**–**
Company Total	**14.3**	**12.6**	**19.3**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment as at June 30, 2014.

** Total wells brought on-stream during the quarter regardless of when they were drilled.

Asset Activity

Our second quarter capital spending totaled $204 million, down slightly from the first quarter. This investment saw us drill 14.3 net horizontal wells and place 19.3 net wells on-stream, the majority of which were in our Bakken/Three Forks and Marcellus plays.

At Fort Berthold, we invested $98.6 million in the quarter with 6.9 net wells drilled targeting a mix of Bakken and Three Forks horizons. We also completed and brought on-stream 5.1 net wells, including our two top performing wells, one Bakken and one second bench Three Forks, which produced an average of approximately 2,400 barrels per day per well in their first 30 days (cumulative production of over 70,000 barrels of oil each). Daily production increased by 14% at Fort Berthold over the first quarter of 2014, averaging 20,800 BOE per day, a new high for this project.

In the Marcellus, our operations continued to be focused in Wyoming, Susquehanna, Bradford and Sullivan counties. During the quarter we invested $45.1 million, drilling and bringing on-stream 5.9 net wells. Production averaged a record 189 MMcf per day, up 5% compared to the first quarter of the year, and more than double from the production rate in the second quarter of 2013.

We also invested $28.1 million into our low-decline Canadian oil waterflood portfolio for both near and long-term growth, increasing production slightly quarter over quarter. At Brooks, we continued to advance our 60-well drilling program targeting the Lower Mannville sands and we are moving forward with the second phase of development in our polymer project at Medicine Hat.

Consistent with our on-going portfolio management, we expect to sell non-core gas weighted properties with production of 2,500 BOE to 3,500 BOE per day with closing early in the fourth quarter.

Summary

We have delivered another quarter of consistent operational execution which is driving production growth and further confirming the sustainability of our business. We are proud to be hitting record production levels while maintaining our capital discipline and strong financial position. We remain focused on achieving our operating and financial targets and creating value for our shareholders.

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 August 7, 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 six months ended June 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 to evaluate 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 to analyze 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 June 30,		Six months ended June 30,	
Reconciliation of Cash Flow from Operating Activities to Funds Flow	**2014**	**2013**	**2014**	**2013**
Cash flow from operating activities	$ 228,506	$ 195,424	$ 368,916	$ 356,658
Asset retirement obligation expenditures	4,240	2,957	8,532	6,335
Changes in non-cash operating working capital	(19,535)	6,325	56,275	14,312
Funds flow	$ 213,211	$ 204,706	$ 433,723	$ 377,305

"Debt to Funds Flow Ratio" is used to analyze 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 to analyze 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

Our strong operational performance continued during the second quarter with production of 103,987 BOE/day, up 15% from the same period a year ago and up 5% from the prior quarter. Based on our year to date performance, we have increased our annual production guidance to 100,000-104,000 BOE/day from 96,000-100,000 BOE/day and are on track to deliver approximately 5% crude oil and liquids growth, with production of 44,000 bbls/day. Our capital program remained on track with spending of $204.4 million during the quarter and we are maintaining our capital spending guidance for 2014 of $800 million. With the strength of our balance sheet and the anticipated proceeds from our non-core divestments, we are evaluating opportunities to modestly increase spending in our core areas and plan to review spending levels in the third quarter.

Funds flow in the second quarter totaled $213.2 million compared to $204.7 million in the same period in 2013 and $220.5 million in the first quarter of 2014. The decrease in funds flow compared to the first quarter of 2014 was primarily a result of lower natural gas prices and a wider Marcellus differential to NYMEX, offset by higher crude oil prices. Operating costs and cash general and administrative costs came in better than expected at $10.09/BOE and $1.97/BOE, respectively, and as a result we are lowering our 2014 guidance for operating costs and cash general and administrative to $10.10/BOE (from $10.25/BOE) and $2.30/BOE (from $2.45/BOE). Our share price rose by approximately $4.80 or 22% during the second quarter, which led to an increase in our cash share-based compensation expense. Accordingly, we are increasing our cash share-based compensation guidance to $0.60/BOE from $0.45/BOE.

We continue to maintain our financial flexibility and strong balance sheet. Our trailing 12 month debt to funds flow ratio was 1.3x and we had $706.7 million of undrawn credit capacity at quarter end. In June, we signed agreements and priced a US$200.0 million private placement of senior unsecured notes with a ten year average life and an interest rate of 3.79%. The debt issue is expected to close in early September and proceeds will be used to repay outstanding debt.

RESULTS OF OPERATIONS

Production

Production increased by 5% to 103,987 BOE/day in the second quarter of 2014 from 98,821 BOE/day in the first quarter. Crude oil volumes grew by 6% due to our ongoing development program in Fort Berthold, while natural gas volumes rose by 5% as a result of the strong performance of our Marcellus assets.

Compared to the second quarter of 2013, production increased 15% or 13,950 BOE/day. Natural gas volumes grew by approximately 25% due to our ongoing development activity in the Marcellus, along with the December 2013 acquisition of additional working interests in our existing Marcellus properties. Over the same period, our crude oil volumes increased by approximately 5% due to growth in our Fort Berthold production volumes and despite divestments of approximately 2,100 BOE/day of non-core Canadian crude oil production in the second half of 2013.

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

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

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2014**	**2013**	**% Change**	**2014**	**2013**	**% Change**
Crude oil (bbls/day)	39,863	38,066	5%	38,817	38,193	2%
Natural gas liquids (bbls/day)	3,636	3,497	4%	3,450	3,546	(3)%
Natural gas (Mcf/day)	362,929	290,841	25%	354,906	281,275	26%
Total daily sales (BOE/day)	103,987	90,037	15%	101,418	88,618	14%

As a result of strong operational performance, we are increasing our annual average production guidance to 100,000-104,000 BOE/day from 96,000-100,000 BOE/day, with crude oil and natural gas liquids expected to contribute approximately 44,000 bbls/day. This revised production guidance assumes anticipated divestments of non-core gas weighted properties in Canada with production of approximately 2,500 to 3,500 BOE/day in the fourth quarter.

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 six month period ended June 30, 2014 and 2013 and quarterly average prices from the second quarter of 2014 to the second quarter of 2013.

	Six months ended June 30,						
Pricing (average for the period)	**2014**	**2013**	**Q2 2014**	**Q1 2014**	**Q4 2013**	**Q3 2013**	**Q2 2013**
Benchmarks							
WTI crude oil (US$/bbl)	$ 100.84	$ 94.30	$ 102.99	$ 98.68	$ 97.46	$ 105.82	$ 94.22
AECO natural gas – monthly index (CDN$/Mcf)	4.72	3.34	4.68	4.76	3.16	2.82	3.59
AECO natural gas – daily index (CDN$/Mcf)	5.20	3.37	4.69	5.71	3.53	2.43	3.53
NYMEX natural gas – last day (US$/Mcf)	4.80	3.71	4.67	4.94	3.60	3.58	4.09
US/CDN exchange rate	1.10	1.02	1.09	1.10	1.05	1.04	1.02
Enerplus selling price [1]							
Crude oil (CDN$/ bbl)	$ 93.25	$ 80.74	$ 94.90	$ 91.48	$ 77.77	$ 96.30	$ 82.95
Natural gas liquids (CDN$/ bbl)	57.66	52.16	49.98	66.30	54.26	49.88	45.64
Natural gas (CDN$/ Mcf)	4.46	3.41	4.02	4.93	3.26	2.96	3.70
Average differentials (US$/bbl or US$/Mcf)							
MSW Edmonton – WTI	$ (7.19)	$ (5.31)	$ (6.13)	$ (8.25)	$ (14.93)	$ (4.72)	$ (3.67)
WCS Hardisty – WTI	(21.59)	(25.56)	(20.04)	(23.13)	(32.20)	(17.48)	(19.16)
Brent Futures (ICE) – WTI	7.97	13.69	6.75	9.19	11.86	3.83	9.14
AECO monthly – NYMEX	(0.50)	(0.43)	(0.38)	(0.63)	(0.60)	(0.86)	(0.58)
Enerplus realized differentials [1]							
Canada crude oil – WTI	$ (19.19)	$ (22.03)	$ (17.80)	$ (20.70)	$ (30.73)	$ (15.18)	$ (16.97)
Canada natural gas – NYMEX	(0.51)	(0.62)	(0.71)	(0.31)	(0.63)	(1.06)	(0.78)
Bakken crude oil – WTI	$ (12.87)	$ (7.89)	$ (14.55)	(11.85)	(17.47)	(11.41)	(9.61)
Marcellus natural gas – NYMEX	(1.20)	(0.11)	(1.50)	(0.88)	(0.50)	(0.52)	(0.12)

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

Crude Oil and Natural Gas Liquids

WTI prices increased by 4% during the second quarter of 2014 due to elevated tensions in the Middle East and decreased U.S. storage levels as refiners ran at high utilization rates. In particular, balances at Cushing, the WTI pricing hub, decreased significantly during the quarter due to increased take away. The market rallied strongly in June on fears of a potential supply disruption in Iraq, driving spot WTI prices to reach an intra-day high of US$107.73/bbl.

Crude oil differentials in Canada improved in the second quarter, with WCS averaging US$20.04/bbl below WTI and light sweet differentials averaging US$6.13/bbl below WTI. The improvement in differentials was largely due to scheduled maintenance by oil sands producers that restricted production during the period. We expect that incremental downstream pipeline capacity coming into service in the second half of 2014 will help support Canadian differential prices for the remainder of the year. Our realized differential for Canadian crude oil improved during the second quarter averaging US$17.80/bbl below WTI compared to US$20.70/bbl in the first quarter.

Our average realized Bakken differential widened during the quarter, to US$14.55/bbl below WTI from US$11.85/bbl in the first quarter, as our volumes being shipped by rail grew during the quarter and rail netbacks fell.

Natural Gas

U.S. natural gas prices weakened throughout the second quarter as injections into storage facilities were much higher compared to the same period in 2013 due to cooler than normal weather conditions across much of the key U.S. demand centres. In Canada, AECO differentials to NYMEX narrowed to US$0.38/Mcf below NYMEX during the second quarter compared to US$0.63/Mcf in the first quarter.

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. During the first quarter, our realized differentials were positively impacted by the volatility of the AECO daily index, while the second quarter saw no material differences between AECO month and day index.

Natural gas prices in the Marcellus weakened considerably in the second quarter as cooler temperatures resulted in lower than expected demand for gas-fired power generation. When combined with an estimated net supply increase of over 1.5 Bcf/day in the Northeast U.S. relative to last year, regional spot price differentials to NYMEX in the Marcellus widened from an average of approximately US$0.88/Mcf below NYMEX in April to as much as US$2.30/Mcf below NYMEX in June. Approximately 56% of our Marcellus production during the quarter was exposed to these regional spot prices contributing to our realized Marcellus price differential of US$1.50/Mcf below NYMEX for the quarter. We now expect an annual realized Marcellus price differential of US$1.35/Mcf below NYMEX for 2014.

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. Following a rapid depreciation of the Canadian dollar in the first quarter of 2014, the dollar regained some ground in the second quarter supported by higher oil prices and rising inflation. After reaching a low of 1.1251 near the close of the first quarter, the Canadian dollar rose to 1.0676 at June 30, 2014. As the dollar weakened in the first quarter, we entered into costless collars on our oil and gas sales to protect a portion of our anticipated revenues at favorable exchange rates.

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. We have increased our crude oil hedges significantly since last quarter. As of July 23, 2014 we have swapped an average of 21,000 bbls/day from July 1, 2014 to December 31, 2014 at an average price of US$95.42/bbl, which represents approximately 68% of our forecasted net crude oil production after royalties. For the first half of 2015, we have swapped 15,500 bbls/day at an average price of US$93.58/bbl, which represents approximately 50% of our forecasted net crude oil production after royalties. Additionally, we have 8,000 bbls/d swapped for the second half of 2015 at an average price of US$93.86/bbl, which represents approximately 26% of our forecasted net crude oil production after royalties.

We have entered into WCS differential swap positions for 2014 to manage our exposure to widening heavy crude oil differentials. These differential swaps have been fixed at an average price of WTI less a fixed spread of US$21.00/bbl on 3,000 bbls/day from July through September of 2014 and 4,000 bbls/day from October through December of 2014. We have also entered into 3,000 bbl/day of Brent-WTI differential swap positions for the remainder of 2014 to shift some of our WTI price exposure to Brent based pricing, selling WTI at an average of 92.63% of Brent pricing.

As of July 23, 2014 we have downside protection on approximately 50% of our forecasted natural gas production after royalties for the remainder of 2014 consisting of NYMEX swaps at US$4.14/Mcf on 28% of production, NYMEX collars at US$4.30 – $5.08/Mcf on 11% of production and AECO swaps at an average price of $4.25/Mcf on 11% of production. Overall for 2015, we have downside protection on approximately 23% of our forecasted annual natural gas production after royalties comprised of NYMEX swaps at an average price of US$4.26/Mcf on 20% of production and NYMEX collars in the first quarter at US$4.53 -$5.53/Mcf on 3% of forecasted annual production.

We have foreign exchange costless collars in place 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 July 23, 2014 we have US$12.0 million per month hedged for the remainder of 2014 at an average USD/CDN floor of 1.1046, ceiling of 1.1558 and conditional ceiling of 1.1198. Under these contracts, if the monthly foreign exchange rate settles above the ceiling rate the conditional ceiling is used to determine the settlement amount. For 2015, we have US$12.0 million per month hedged at an average USD/CDN floor of 1.1083, ceiling of 1.1900 and conditional ceiling of 1.1254. During the second quarter, we recorded cash gains of $0.4 million and non-cash mark-to-market gains of $6.7 million on the contracts.

The following is a summary of our financial contracts in place at July 23, 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]			
	Jul 1, 2014 – Sep 30, 2014	Oct 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015	Jul 1, 2014 – Dec 31, 2014	Jul 1, 2014 – Dec 31, 2014	Jan 1, 2015 – Mar 31, 2015	Apr 1, 2015 – Jun 30, 2015	Jul 1, 2015 – Dec 31, 2015
Purchased Puts	–	–	–	–	–	$ 4.30	$ 4.53	–	–
%	–	–	–	–	–	11%	11%	–	–
Sold Puts	–	–	–	–	–	$ 3.23	–	–	–
%	–	–	–	–	–	9%	–	–	–
Swaps	$ 95.54	$ 95.29	$ 93.58	$ 93.86	$ 4.25	$ 4.14	$ 4.31	$ 4.31	$ 4.21
%	71%	65%	50%	26%	11%	28%	24%	24%	17%
Sold Calls	–	–	–	–	–	$ 5.04	$ 5.53	–	–
%	–	–	–	–	–	20%	11%	–	–
Purchased Calls	–	–	–	–	–	$ 4.17	–	–	–
%	–	–	–	–	–	9%	–	–	–

(1) Based on weighted average price (before premiums), assumed average annual production of 100,000 – 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 June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Cash gains/(losses):				
Crude oil	$ (21.2)	$ 11.0	$ (32.0)	$ 21.9
Natural gas	(3.3)	(1.9)	(7.9)	(1.2)
Total cash gains/(losses)	$ (24.5)	$ 9.1	$ (39.9)	$ 20.7
Non-cash gains/(losses):				
Change in fair value – crude oil	$ (24.8)	$ 8.7	$ (34.2)	$ (20.9)
Change in fair value – natural gas	5.3	12.8	(2.6)	3.8
Total non-cash gains/(losses)	$ (19.5)	$ 21.5	$ (36.8)	$ (17.1)
Total gains/(losses)	$ (44.0)	$ 30.6	$ (76.7)	$ 3.6

(Per BOE)	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Total cash gains/(losses)	$ (2.60)	$ 1.11	$ (2.17)	$ 1.29
Total non-cash gains/(losses)	(2.06)	2.63	(2.01)	(1.07)
Total gains/(losses)	$ (4.66)	$ 3.74	$ (4.18)	$ 0.22

During the second quarter of 2014, we realized cash losses of $21.2 million on our crude oil contracts and $3.3 million on our natural gas contracts. In comparison, during the second quarter of 2013, we realized cash gains of $11.0 million on our crude oil contracts and cash losses of $1.9 million on our natural gas contracts. The cash losses realized in 2014 were a result of crude oil and natural gas prices rising above our fixed price swap positions. The crude oil cash gains in 2013 were due to 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 second quarter of 2014 the fair value of our crude oil and natural gas contracts represented net loss positions of $49.0 million and $2.3 million, respectively. For the three and six months ended June 30, 2014 the change in the fair value of our crude oil contracts represented losses of $24.8 million and $34.2 million, respectively, while the change in fair value of our natural gas contracts represented a gain of $5.3 million and a loss of $2.6 million, respectively.

Revenues

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Oil and natural gas sales	$ 504.5	$ 404.8	$ 999.5	$ 778.2
Royalties	(89.6)	(63.5)	(176.9)	(123.5)
Oil and natural gas sales, net of royalties	$ 414.9	$ 341.3	$ 822.6	$ 654.7

Oil and natural gas sales were $504.5 million in the second quarter of 2014, an increase of 25% or $99.7 million compared to the same period in 2013. For the six months ended June 30, 2014 oil and natural gas sales were $999.5 million, an increase of 28% or $221.3 million compared to the same period a year ago. The increase in revenues was related to higher production and improved realized prices.

Royalties and Production Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Royalties	$ 89.6	$ 63.5	$ 176.9	$ 123.5
Production taxes	20.0	17.9	39.8	32.5
Royalties and production taxes	$ 109.6	$ 81.4	$ 216.7	$ 156.0
As a % of oil and natural gas sales, net of transportation	22%	20%	22%	20%

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2014	2013	2014	2013
Royalties	$ 9.47	$ 7.75	$ 9.64	$ 7.70
Production taxes	2.11	2.18	2.17	2.03
Royalties and production taxes	$ 11.58	$ 9.93	$ 11.81	$ 9.73
As a % of oil and natural gas sales, net of transportation	22%	20%	22%	20%

Royalties are paid to government entities, land owners and mineral rights owners. Production taxes include state production taxes, Pennsylvania impact fees, freehold mineral taxes and Saskatchewan resource surcharges. During the three and six months ended June 30, 2014 royalties and production taxes increased to $109.6 million and $216.7 million, respectively, from $81.4 million and $156.0 million for the same period a year ago. This upward trend is primarily due to higher realized prices and increased production from higher royalty rate U.S. properties. Royalties and production taxes averaged 22% of oil and gas sales (net of transportation) in 2014 compared to 20% in 2013.

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

Operating Expenses

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
Operating Expenses	$ 95.5	$ 85.4	$ 184.6	$ 166.7
Per BOE	$ 10.09	$ 10.42	$ 10.06	$ 10.39

Our operating expenses for the three and six months ended June 30, 2014 were $95.5 million or $10.09/BOE and $184.6 million or $10.06/BOE respectively. In comparison, we had operating costs of $85.4 million or $10.42/BOE and $166.7 million or $10.39/BOE for the same periods in 2013. The current year operating costs have decreased on a per BOE basis mainly due to the higher production from our lower cost Marcellus and Fort Berthold properties.

Based on our increased production guidance and continued focus on cost control, we are reducing our annual guidance for operating costs to $10.10/BOE from $10.25/BOE.

Transportation Costs

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
Transportation costs	$ 13.1	$ 6.2	$ 26.2	$ 13.4
Per BOE	$ 1.39	$ 0.76	$ 1.43	$ 0.84

Transportation costs for the three and six months ended June 30, 2014 were $13.1 million and $26.2 million, respectively, compared to $6.2 million and $13.4 million 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 six months ended June 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 June 30, 2014		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	44,681 BOE/day	355,836 Mcfe/day	103,987 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 86.94	$ 4.26	$ 51.93
Royalties and production taxes	(21.06)	(0.74)	(11.58)
Cash operating costs	(13.17)	(1.30)	(10.12)
Netback before hedging	$ 52.71	$ 2.22	$ 30.23
Cash gains/(losses)	(5.23)	(0.10)	(2.60)
Netback after hedging	$ 47.48	$ 2.12	$ 27.63
Netback before hedging ($ millions)	$ 214.4	$ 71.7	$ 286.1
Netback after hedging ($ millions)	$ 193.1	$ 68.4	$ 261.5

Netbacks by Property Type	Three months ended June 30, 2013 Crude Oil	Natural Gas	Total
Average Daily Production	42,753 BOE/day	283,704 Mcfe/day	90,037 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 75.70	$ 4.03	$ 48.65
Royalties and production taxes	(17.13)	(0.57)	(9.93)
Cash operating costs	(13.19)	(1.36)	(10.55)
Netback before hedging	$ 45.38	$ 2.10	$ 28.17
Cash gains/(losses)	2.82	(0.07)	1.11
Netback after hedging	$ 48.20	$ 2.03	$ 29.28
Netback before hedging ($ millions)	$ 176.6	$ 54.2	$ 230.8
Netback after hedging ($ millions)	$ 187.5	$ 52.4	$ 239.9

Netbacks by Property Type	Six months ended June 30, 2014 Crude Oil	Natural Gas	Total
Average Daily Production	43,519 BOE/day	347,394 Mcfe/day	101,418 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 86.29	$ 4.67	$ 53.03
Royalties and production taxes	(21.19)	(0.79)	(11.81)
Cash operating costs	(13.28)	(1.28)	(10.07)
Netback before hedging	$ 51.82	$ 2.60	$ 31.15
Cash gains/(losses)	(4.05)	(0.13)	(2.17)
Netback after hedging	$ 47.77	$ 2.47	$ 28.98
Netback before hedging ($ millions)	$ 408.2	$ 163.6	$ 571.8
Netback after hedging ($ millions)	$ 376.2	$ 155.7	$ 531.9

Netbacks by Property Type	Six months ended June 30, 2013 Crude Oil	Natural Gas	Total
Average Daily Production	42,684 BOE/day	275,604 Mcfe/day	88,618 BOE/day
Netback[1] $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Oil and natural gas sales[2]	$ 74.25	$ 3.83	$ 47.68
Royalties and production taxes	(16.70)	(0.54)	(9.73)
Cash operating costs	(13.01)	(1.36)	(10.48)
Netback before hedging	$ 44.54	$ 1.93	$ 27.47
Cash gains/(losses)	2.83	(0.02)	1.29
Netback after hedging	$ 47.37	$ 1.91	$ 28.76
Netback before hedging ($ millions)	$ 344.1	$ 96.5	$ 440.6
Netback after hedging ($ millions)	$ 366.0	$ 95.3	$ 461.3

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

Our crude oil properties accounted for 71% of our corporate netback before hedging for the year to date compared to 78% for the same period in 2013. Crude oil netbacks per BOE increased for the three and six months ended June 30, 2014 compared to the same periods in 2013 primarily due to higher realized crude oil prices partially offset by higher royalties as a result of increased U.S. production. Natural gas netbacks per Mcfe decreased slightly during the second quarter compared to the same period last year due to weakened gas prices and widening differentials. Strong gas prices in the first quarter led to an increase in the natural gas netback for the six months ended June 30, 2014 compared to the same period in 2013.

General and Administrative Expenses ("G&A")

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 June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Cash:				
G&A expense[1]	$ 18.7	$ 18.8	$ 39.2	$ 43.5
SBC	10.7	3.7	17.5	9.2
Non-Cash:				
SBC	3.5	3.0	6.5	5.5
SBC – equity swap loss/(gain)	(4.7)	(0.8)	(5.9)	(2.3)
Total G&A expenses	$ 28.2	$ 24.7	$ 57.3	$ 55.9

	Three months ended June 30,		Six months ended June 30,	
(Per BOE)	2014	2013	2014	2013
Cash:				
G&A expense[1]	$ 1.97	$ 2.29	$ 2.14	$ 2.71
SBC	1.12	0.45	0.95	0.57
Non-Cash:				
SBC	0.37	0.36	0.35	0.34
SBC – equity swap loss/(gain)	(0.49)	(0.09)	(0.32)	(0.14)
Total G&A expenses	$ 2.97	$ 3.01	$ 3.12	$ 3.48

(1) Excluding SBC.

Cash G&A expenses during the second quarter were in line with our expectations at $18.7 million or $1.97/BOE compared to $18.8 million or $2.29/BOE in the second quarter of 2013. For the six months ended June 30, 2014 cash G&A expenses were $39.2 million or $2.14/BOE compared to $43.5 million or $2.71/BOE for the same period in 2013. The decrease during 2014 was mainly due to one-time charges recorded in the prior year associated with the departure of personnel. Higher production volumes in 2014 have also helped to decrease our reported G&A on a per BOE basis.

Cash SBC expense increased during 2014 due to the increase in our share price, which had risen by 39% during the six months ended June 30, 2014. For the second quarter of 2014, cash SBC expense was $10.7 million or $1.12/BOE compared to $3.7 million or $0.45/BOE during the second quarter of 2013. For the six months ended June 30, 2014 cash SBC expense was $17.5 million or $0.95/BOE compared to $9.2 million or $0.57/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 $14.78/share. As a result of the increase in our share price we recorded non-cash mark-to-market gains of $4.7 million and $5.9 million for the three and six months ended June 30, 2014, respectively.

We are reducing our 2014 guidance for cash G&A expense to $2.30/BOE from $2.45/BOE based on our revised production guidance and continued focus on cost control. We are also increasing our 2014 guidance for cash SBC to $0.60/BOE from $0.45/BOE based on our share price at June 30, 2014.

Interest Expense

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Interest on senior notes and bank facility	$ 16.0	$ 14.3	$ 30.6	$ 28.5
Non-cash interest expense	0.5	0.5	1.1	0.7
Total interest expense	$ 16.5	$ 14.8	$ 31.7	$ 29.2

For the three and six months ended June 30, 2014 we recorded total interest expense of $16.5 million and $31.7 million, respectively, compared to $14.8 million and $29.2 million in the same periods in 2013. Despite a decreasing debt balance, interest on our senior notes increased slightly year over year due to the impact of a weaker Canadian dollar on our U.S. dollar denominated interest payments.

Non-cash amounts recorded in interest expense include unrealized gains and losses resulting from the change in fair value of the interest component of our cross currency interest rate swap ("CCIRS") and amortization of deferred financing charges.

At June 30, 2014, after including our underlying derivatives, approximately 72% of our debt was based on fixed interest rates and 28% on floating interest rates.

Foreign Exchange

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Realized loss/(gain)	$ 16.6	$ 14.9	$ 16.7	$ 17.6
Unrealized loss/(gain)	(23.8)	(12.7)	(22.5)	(11.1)
Total foreign exchange loss/(gain)	$ (7.2)	$ 2.2	$ (5.8)	$ 6.5

We recorded a net foreign exchange gain of $7.2 million during the second quarter and a gain of $5.8 million year to date, compared to net losses of $2.2 million and $6.5 million during the same periods in 2013.

On June 19, 2014 we made the final US$35.0 million principal repayment on our US$175.0 million senior notes and corresponding CCIRS settlement, which resulted in a $15.8 million realized foreign exchange loss. The remaining realized losses during the quarter related to day-to-day transactions denominated in foreign currencies.

Unrealized foreign exchange gains in the quarter related to the translation of our U.S. dollar debt and working capital and the reversal of cumulative mark-to-market losses on the final settlement of our CCIRS.

Capital Investment and Dispositions

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Capital spending	$ 204.4	$ 139.7	$ 422.2	$ 312.6
Office capital	1.2	0.8	1.6	2.2
Sub-total	$ 205.6	$ 140.5	$ 423.8	$ 314.8
Property and land acquisitions	$ 3.2	$ 51.7	$ 13.2	$ 55.7
Property dispositions	0.5	(71.3)	(116.7)	(72.6)
Sub-total	$ 3.7	$ (19.6)	$ (103.5)	$ (16.9)
Total net capital investment	$ 209.3	$ 120.9	$ 320.3	$ 297.9

Capital spending for the second quarter totaled $204.4 million compared to $139.7 million during the same period in 2013. We continue to focus our spending on our core development areas. Crude oil spending for the quarter included $98.6 million at Fort Berthold and $28.1 million on our Canadian waterflood properties. Natural gas spending included $45.1 million in the Marcellus and $31.0 million on our Deep Basin assets.

We completed minor property and land acquisitions totaling $3.2 million during the quarter. In the second quarter of 2013 we spent $51.7 million, which included $34.0 million for the acquisition of an incremental 50% working interest in our Pouce Coupe light oil waterflood property as well as $16.7 million on land acquisitions around our existing acreage in the U.S.

Property dispositions of $71.3 million in the second quarter of 2013 included the sale of our Taylorton and Turner Valley non-core oil asset for proceeds of $57.2 million along with other minor dispositions totaling $14.1 million.

We are maintaining our capital spending guidance at $800 million. However, given the strength of our balance sheet and anticipated divestment proceeds, we are evaluating opportunities in our core areas and may modestly increase spending in the second half of the year.

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

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per BOE amounts)	2014	2013	2014	2013
DDA&A expense	$ 148.7	$ 160.5	$ 280.8	$ 306.7
Per BOE	$ 15.71	$ 19.59	$ 15.30	$ 19.12

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 six months ended June 30, 2014 DDA&A decreased to $148.7 million and $280.8 million, respectively, compared to $160.5 million and $306.7 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 in 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 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 $288.6 million at June 30, 2014 compared to $291.8 million at December 31, 2013.

Income Taxes

	Three months ended June 30,		Six months ended June 30,	
($ millions)	2014	2013	2014	2013
Current tax expense	$ 3.8	$ 1.4	$ 11.5	$ 2.7
Deferred tax expense	12.7	20.3	37.2	22.2
Total tax expense	$ 16.5	$ 21.7	$ 48.7	$ 24.9

We recorded total tax expense of $16.5 million and $48.7 million for the three and six months ended June 30, 2014, respectively, compared to $21.7 million and $24.9 million for the same periods in 2013. For the three months ended June 30, 2014 the decrease in total tax expense relates primarily to the decrease in net income for tax purposes. For the six months ended June 30, 2014 higher revenues caused net income for tax purposes to increase resulting in an increase in tax expense.

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. Based on current commodity prices and assuming no acquisition and divestment activity, we expect to pay U.S. cash taxes of between 3% to 5% of our U.S. funds flow for 2014 and 2015. We expect to continue to pay U.S. AMT through 2018 with the rate gradually increasing to approximately 15% over that time. 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 six months ended June 30, 2014 and 2013.

	Three months ended June 30, 2014			Three months ended June 30, 2013		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes[1]						
Crude oil (bbls/day)	17,184	22,679	39,863	18,364	19,702	38,066
Natural gas liquids (bbls/day)	2,476	1,160	3,636	2,975	522	3,497
Natural gas (Mcf/day)	156,401	206,528	362,929	186,569	104,272	290,841
Total average daily production (BOE/day)	45,727	58,260	103,987	52,434	37,603	90,037
Pricing[2]						
Crude oil (per bbl)	$ 92.90	$ 96.41	$ 94.90	$ 79.06	$ 86.58	$ 82.95
Natural gas liquids (per bbl)	57.01	35.00	49.98	49.05	26.21	45.64
Natural gas (per Mcf)	4.32	3.80	4.02	3.39	4.26	3.70
Capital Expenditures						
Capital spending	$ 60.4	$ 144.0	$ 204.4	$ 44.4	$ 95.3	$ 139.7
Acquisitions	–	3.2	3.2	35.0	16.7	51.7
Dispositions	–	0.5	0.5	(63.9)	(7.4)	(71.3)
Netback Before Hedging						
Oil and natural gas sales	$ 226.0	$ 278.5	$ 504.5	$ 208.9	$ 195.9	$ 404.8
Royalties	(35.1)	(54.5)	(89.6)	(25.5)	(38.0)	(63.5)
Operating expense	(62.2)	(33.5)	(95.7)	(64.9)	(21.5)	(86.4)
Production taxes	(1.9)	(18.1)	(20.0)	(5.0)	(12.9)	(17.9)
Transportation expense	(5.9)	(7.2)	(13.1)	(5.4)	(0.8)	(6.2)
Netback before hedging	$ 120.9	$ 165.2	$ 286.1	$ 108.1	$ 122.7	$ 230.8
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 44.0	$ –	$ 44.0	$ 30.6	–	$ 30.6
General and administrative expense	22.6	5.6	28.2	21.1	3.6	24.7
Current income tax expense/(recovery)	(0.2)	4.0	3.8	0.1	1.3	1.4

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

(CDN$ millions, except per unit amounts)	Six months ended June 30, 2014 Canada	U.S.	Total	Six months ended June 30, 2013 Canada	U.S.	Total
Average Daily Production Volumes(1)						
Crude oil (bbls/day)	16,882	21,935	38,817	18,764	19,429	38,193
Natural gas liquids (bbls/day)	2,508	942	3,450	3,045	501	3,546
Natural gas (Mcf/day)	154,027	200,879	354,906	182,214	99,061	281,275
Total average daily production (BOE/day)	45,061	56,357	101,418	52,178	36,440	88,618
Pricing(2)						
Crude oil (per bbl)	$ 89.55	$ 96.09	$ 93.25	$ 73.44	$ 87.80	$ 80.74
Natural gas liquids (per bbl)	63.16	43.01	57.66	55.81	30.02	52.16
Natural gas (per Mcf)	4.70	4.28	4.46	3.15	3.90	3.41
Capital Expenditures						
Capital spending	$ 188.0	$ 234.2	$ 422.2	$ 127.4	$ 185.2	$ 312.6
Acquisitions	–	13.2	13.2	37.6	18.1	55.7
Dispositions	(67.7)	(49.0)	(116.7)	(65.2)	(7.4)	(72.6)
Netback Before Hedging						
Oil and natural gas sales	$ 446.0	$ 553.5	$ 999.5	$ 397.1	$ 381.1	$ 778.2
Royalties	(69.1)	(107.8)	(176.9)	(50.4)	(73.1)	(123.5)
Operating expense	(124.4)	(60.4)	(184.8)	(131.4)	(36.8)	(168.2)
Production taxes	(3.9)	(35.9)	(39.8)	(6.4)	(26.1)	(32.5)
Transportation expense	(11.7)	(14.5)	(26.2)	(11.8)	(1.6)	(13.4)
Netback before hedging	$ 236.9	$ 334.9	$ 571.8	$ 197.1	$ 243.5	$ 440.6
Other Expenses						
Commodity derivative instruments loss/(gain)	$ 76.7	$ –	$ 76.7	$ 3.6	$ –	$ 3.6
General and administrative expense	45.9	11.4	57.3	49.0	6.9	55.9
Current income tax expense/(recovery)	(0.4)	11.9	11.5	0.1	2.6	2.7

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

QUARTERLY FINANCIAL INFORMATION

(CDN$ millions, except per share amounts)	Oil and Natural Gas Sales, Net of Royalties	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Diluted
2014				
Second Quarter	$ 414.9	$ 40.0	$ 0.20	$ 0.19
First Quarter	407.7	40.0	0.20	0.19
Total	$ 822.6	$ 80.0	$ 0.39	$ 0.39
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 increased in the second quarter of 2014 due to higher production volumes which were partially offset by lower realized natural gas prices compared to the first quarter. Oil and gas sales grew during 2013 with increasing production volumes. Net income grew in 2014 compared to 2013 from increased production and realized prices. Net income in 2012 was lower due to asset impairments recorded during the year.

LIQUIDITY AND CAPITAL RESOURCES

We continued to maintain a strong balance sheet and ample liquidity through the second quarter. At June 30, 2014 we had a conservative trailing 12 month debt to cash flow ratio of 1.3x and approximately $706.7 million of undrawn credit capacity. On June 19, 2014 we made the final principal payment on our US$175.0 million senior notes and the related CCIRS settlement. During the quarter, we entered into agreements to issue US$200.0 million of senior unsecured notes on a private placement basis. The notes, which are expected to close on September 3, 2014, have a twelve year amortizing term with a ten year average life and a fixed interest rate of 3.79%. We plan to use the proceeds to repay our short-term, floating interest rate bank debt.

Our adjusted payout ratio, calculated as dividends (net of SDP proceeds) plus capital and office spending, divided by funds flow, increased to 120% and 119% for the three and six months ended June 30, 2014, respectively, compared to 89% and 106% for the same periods in 2013. Although funds flow increased by 4% and 15% for the three and six months ended June 2014 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.

Total debt net of cash at June 30, 2014 was $1,067.6 million, including current portion, compared to $1,022.3 million at December 31, 2013. Total debt was comprised of $293.3 million of bank indebtedness and $776.3 million of senior notes, less $2.0 million in cash. Our working capital deficiency, excluding cash and current deferred financial and tax assets and credits, increased slightly during the quarter to $251.2 million from $226.1 million. Although receivables increased due to higher production levels, this was offset by a higher current portion of long-term debt related to senior note maturities in June of 2015. 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	June 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)	13.8 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 June 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.

Dividends

	Three months ended June 30,		Six months ended June 30,	
($ millions, except per share amounts)	2014	2013	2014	2013
Cash dividends	$ 50.5	$ 42.6	$ 92.7	$ 86.3
Stock dividend plan	4.7	11.4	17.4	21.5
Total dividends to shareholders	$ 55.2	$ 54.0	$ 110.1	$ 107.8
Per weighted average share (Basic)	$ 0.27	$ 0.27	$ 0.54	$ 0.54

During the three and six months ended June 30, 2014 we recorded dividends to our shareholders of $55.2 million ($0.27/share) and $110.1 million ($0.54/share), respectively, compared to $54.0 million ($0.27/share) and $107.8 million ($0.54/share) for the same periods in 2013. For the first six months of 2014, dividend payments including SDP amounted to 25% of our funds flow of $433.7 million. We will continue to assess 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.

Participation in the SDP is optional allowing our shareholders to continue to receive cash dividends unless they elect to receive stock dividends. As a result of our improved sustainability and strong balance sheet, in April of this year we eliminated the 5% discount with the intention of reducing shareholder dilution. Subsequently, our participation rate in the SDP decreased significantly to approximately 9% where we had previously been averaging 23%. Participation in the SDP for July was approximately $1.7 million compared to approximately $4.2 million per month in the first quarter.

Shareholders' Capital

	Six months ended June 30,	
	2014	2013
Share capital ($ millions)	$ 3,102.2	$ 3,019.2
Common shares outstanding (thousands)	204,768	200,268
Weighted average shares outstanding – basic (thousands)	203,671	199,430
Weighted average shares outstanding – diluted (thousands)	207,563	199,586

During the second quarter of 2014, a total of 929,000 shares (2013 – 805,000) and $17.8 million of additional equity (2013 – $11.4 million) was issued pursuant to the SDP and the stock option plan. For the six months ended June 30, 2014, a total of 2,010,000 shares (2013 – 1,584,000) and $36.7 million of additional equity (2013 – $21.5 million) was issued pursuant to the SDP and the stock option plan.

At June 30, 2014 we had 204,768,000 shares outstanding (2013 – 200,268,000) and at August 7, 2014 we had 205,229,771 shares outstanding.

U.S. Filing Status

Pursuant to U.S. securities regulations, we are required to reassess our U.S. securities filing status annually at June 30. As at June 30, 2014 we continued to qualify as a foreign private issuer for the purposes of U.S. reporting requirements.

2014 GUIDANCE

A summary of our 2014 guidance is below.

Summary of 2014 Expectations	Target
Average annual production	100,000 – 104,000 BOE/day (from 96,000 – 100,000 BOE/day)
Production mix (volumes)	44,000 bbls/day crude oil and liquids 56,000-60,000 BOE/day natural gas
Capital spending	$800 million
Average royalty rate (% of gross sales, net of transportation)	23% (from 23.5%)
Operating costs	$10.10/BOE (from $10.25/BOE)
Cash G&A expenses	$2.30 (from $2.45/BOE)
Cash share-based compensation expenses	$0.60/BOE (from $0.45/BOE)
U.S. Cash taxes (% of U.S. funds flow)	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 June 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 April 1, 2014 and ending June 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 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; the amount and timing of future debt issuances and expected use of proceeds therefrom; and future dispositions and acquisitions, including 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.

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	June 30, 2014	December 31, 2013
Assets			
Current assets			
Cash		$ 1,998	$ 2,990
Accounts receivable	3	201,323	165,091
Deferred income tax asset		21,961	48,476
Deferred financial assets	15	17,534	9,198
Other current assets		7,528	7,641
		250,344	233,396
Property, plant and equipment			
Oil and natural gas properties (full cost method)	4	2,471,732	2,420,144
Other capital assets, net	4	18,839	21,210
Property, plant and equipment		2,490,571	2,441,354
Goodwill		610,575	609,975
Deferred income tax asset		355,467	364,411
Deferred financial assets	15	25,926	19,274
Marketable securities	5	–	13,389
Total Assets		$ 3,732,883	$ 3,681,799
Liabilities			
Current liabilities			
Accounts payable	6	$ 347,349	$ 377,157
Dividends payable		18,454	18,250
Current portion of long-term debt	7	94,234	48,713
Deferred financial credits	15	58,956	37,031
		518,993	481,151
Long-term debt	7	975,354	976,585
Asset retirement obligation	8	288,627	291,761
		1,263,981	1,268,346
Total Liabilities		1,782,974	1,749,497
Shareholders' Equity			
Share capital – authorized unlimited common shares, no par value Issued and outstanding: June 30, 2014 – 205 million shares December 31, 2013 – 203 million shares	14	3,102,202	3,061,839
Paid-in capital	14	41,209	38,398
Accumulated deficit		(1,147,393)	(1,117,238)
Accumulated other comprehensive income/(loss)		(46,109)	(50,697)
		1,949,909	1,932,302
Total Liabilities & Equity		$ 3,732,883	$ 3,681,799

Contingencies and Commitments 16

See accompanying notes to the Condensed Consolidated Financial Statements

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

(CDN$ thousands) unaudited	Note	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Revenues					
Oil and natural gas sales, net of royalties	9	$ 414,925	$ 341,324	$ 822,665	$ 654,705
Commodity derivative instruments gain/(loss)	15	(44,069)	30,622	(76,666)	3,567
		370,856	371,946	745,999	658,272
Expenses					
Operating		95,509	85,369	184,590	166,714
Production taxes		19,974	17,860	39,846	32,482
Transportation		13,139	6,232	26,248	13,429
General and administrative	10	28,180	24,666	57,303	55,875
Depletion, depreciation, amortization and accretion		148,656	160,526	280,836	306,749
Interest	11	16,522	14,800	31,701	29,237
Foreign exchange (gain)/loss	12	(7,225)	2,184	(5,756)	6,536
Other expense/(income)		(360)	157	2,552	284
		314,395	311,794	617,320	611,306
Income/(Loss) Before Taxes		56,461	60,152	128,679	46,966
Current income tax expense/(recovery)	13	3,797	1,401	11,475	2,708
Deferred income tax expense/(recovery)	13	12,707	20,284	37,210	22,188
Net Income/(Loss)		$ 39,957	$ 38,467	$ 79,994	$ 22,070
Other Comprehensive Income/(Loss)					
Changes due to marketable securities (net of tax)					
Unrealized gain/(loss)		–	2,345	(145)	2,860
Realized (gain)/loss reclassified to net income		–	–	2,503	(190)
Change in cumulative translation adjustment		(43,414)	37,790	2,230	58,643
Other Comprehensive Income/(Loss)		(43,414)	40,135	4,588	61,313
Total Comprehensive Income/(Loss)		$ (3,457)	$ 78,602	$ 84,582	$ 83,383
Net Income/(Loss) per Share					
Basic		$ 0.20	$ 0.19	$ 0.39	$ 0.11
Diluted		$ 0.19	$ 0.19	$ 0.39	$ 0.11

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Six months ended June 30, (CDN$ thousands) unaudited		**2014**		**2013**
Share Capital				
Balance, beginning of year	$	3,061,839	$	2,997,682
Stock Option Plan – cash		19,193		29
Share-based compensation – non cash		3,683		3
Stock Dividend Plan		17,487		21,495
Balance, end of period	$	3,102,202	$	3,019,209
Paid-in Capital				
Balance, beginning of year	$	38,398	$	32,293
Stock Option Plan – exercised		(3,683)		(3)
Share-based compensation – expensed		6,494		5,478
Balance, end of period	$	41,209	$	37,768
Accumulated Deficit				
Balance, beginning of year	$	(1,117,238)	$	(948,350)
Net income		79,994		22,070
Dividends		(110,149)		(107,794)
Balance, end of period	$	(1,147,393)	$	(1,034,074)
Accumulated Other Comprehensive Income/(Loss)				
Balance, beginning of year	$	(50,697)	$	(130,385)
Changes due to marketable securities (net of tax)				
Unrealized gains/(losses)		(145)		2,860
Realized gains/loss reclassified to net income		2,503		(190)
Change in cumulative translation adjustment		2,230		58,643
Balance, end of period	$	(46,109)	$	(69,072)
Total Shareholders' Equity	$	1,949,909	$	1,953,831

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

(CDN$ thousands) unaudited	Note	Three months ended June 30, 2014	Three months ended June 30, 2013	Six months ended June 30, 2014	Six months ended June 30, 2013
Operating Activities					
Net income/(loss)		$ 39,957	$ 38,467	$ 79,994	$ 22,070
Non-cash items add/(deduct):					
Depletion, depreciation, amortization and accretion		148,656	160,526	280,836	306,749
Changes in fair value of derivative instruments	15	130	(47,943)	6,939	(13,889)
Deferred income tax expense/(recovery)	13	12,707	20,284	37,210	22,188
Foreign exchange (gain)/loss on debt and working capital	12	(9,052)	12,218	1,935	16,538
Share-based compensation	14	3,542	2,951	6,494	5,478
Amortization of debt issue costs		247	192	493	377
Derivative settlement on senior notes		17,024	18,011	17,024	18,011
Asset disposition (gain)/loss		–	–	2,798	(217)
Asset retirement obligation expenditures	8	(4,240)	(2,957)	(8,532)	(6,335)
Changes in non-cash operating working capital	17	19,535	(6,325)	(56,275)	(14,312)
Cash flow from operating activities		228,506	195,424	368,916	356,658
Financing Activities					
Proceeds from the issuance of shares		13,055	8	19,193	29
Cash dividends	14	(50,508)	(42,620)	(92,662)	(86,299)
Change in bank debt		107,280	14,670	76,710	70,089
Repayment of senior notes		(37,898)	(35,655)	(37,898)	(35,655)
Derivative settlement on senior notes		(17,024)	(18,011)	(17,024)	(18,011)
Changes in non-cash financing working capital		103	81	204	151
Cash flow from financing activities		15,008	(81,527)	(51,477)	(69,696)
Investing Activities					
Capital expenditures		(205,623)	(140,465)	(423,816)	(314,841)
Property and land acquisitions		(3,231)	(51,692)	(13,200)	(55,659)
Property dispositions		(525)	71,293	116,700	72,624
Sale of marketable securities	5	–	–	13,300	1,883
Changes in non-cash investing working capital		(35,482)	10,012	(10,805)	20,735
Cash flow from investing activities		(244,861)	(110,852)	(317,821)	(275,258)
Effect of exchange rate changes on cash		(2,392)	(4,842)	(610)	(6,148)
Change in cash		(3,739)	(1,797)	(992)	5,556
Cash, beginning of period		5,737	12,553	2,990	5,200
Cash, end of period		$ 1,998	$ 10,756	$ 1,998	$ 10,756

See accompanying notes to the Condensed Consolidated Financial Statements

Notes to Condensed Consolidated Financial Statements

(unaudited)

1) REPORTING ENTITY

These interim Condensed Consolidated Financial Statements ("interim Consolidated Financial Statements") and notes present the financial position and results of Enerplus Corporation ("The Company" or "Enerplus") including its Canadian and U.S. subsidiaries. Enerplus is a North American crude oil and natural gas exploration and development company. Enerplus is publicly traded on the Toronto and New York stock exchanges under the ticker symbol ERF. Enerplus' head office is located in Calgary, Alberta, Canada. The interim Consolidated Financial Statements were authorized for issue by the Board of Directors on August 7, 2014.

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") as at June 30, 2014 and for the three and six months ended June 30, 2014, and the 2013 comparative periods. These interim Consolidated Financial Statements do not include all the necessary annual disclosures as prescribed under U.S. GAAP and should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2013. 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, 2013.

3) ACCOUNTS RECEIVABLE

($ thousands)	June 30, 2014	December 31, 2013
Accrued receivables	$ 154,290	$ 122,482
Accounts receivable – trade	33,906	36,034
Current income tax receivable	15,960	9,371
Allowance for doubtful accounts	(2,833)	(2,796)
Total accounts receivable	$ 201,323	$ 165,091

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

As at June 30, 2014 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 11,807,080	$ 9,335,348	$ 2,471,732
Other capital assets	91,493	72,654	18,839
Total PP&E	$ 11,898,573	$ 9,408,002	$ 2,490,571

As at December 31, 2013 ($ thousands)	Cost	Accumulated Depletion and Depreciation	Net Book Value
Oil and natural gas properties	$ 11,481,207	$ 9,061,063	$ 2,420,144
Other capital assets	89,818	68,608	21,210
Total PP&E	$ 11,571,025	$ 9,129,671	$ 2,441,354

5) MARKETABLE SECURITIES

During the six months ended June 30, 2014 Enerplus sold the balance of its publicly listed investments for proceeds of $13.3 million recognizing a loss of $2.8 million. In connection with these sales, realized losses of $2.5 million net of tax ($2.8 million before tax) were reclassified from accumulated other comprehensive income to net income.

6) ACCOUNTS PAYABLE

($ thousands)	June 30, 2014	December 31, 2013
Accrued payables	$ 262,213	$ 262,117
Accounts payable – trade	85,136	115,040
Total accounts payable	$ 347,349	$ 377,157

7) DEBT

($ thousands)	June 30, 2014	December 31, 2013
Current:		
Senior notes	$ 94,234	$ 48,713
	$ 94,234	$ 48,713
Long term:		
Bank credit facility	$ 293,263	$ 214,394
Senior notes	682,091	762,191
	$ 975,354	$ 976,585
Total debt	$ 1,069,588	$ 1,025,298

8) ASSET RETIREMENT OBLIGATION

Enerplus has estimated the present value of its asset retirement obligation to be $288.6 million at June 30, 2014 compared to $291.8 million at December 31, 2013, based on a total undiscounted liability of $714.5 million and $720.6 million, respectively. The asset retirement obligation was calculated using a weighted credit-adjusted risk-free rate of 5.93% at June 30, 2014 (December 31, 2013 – 5.96%).

($ thousands)	Six months ended June 30, 2014	Year ended December 31, 2013
Balance, beginning of year	$ 291,761	$ 256,102
Change in estimates	(2,175)	44,217
Property acquisition and development activity	1,039	1,454
Dispositions	(927)	(8,362)
Settlements	(8,532)	(16,606)
Accretion Expense	7,461	14,956
Balance, end of period	$ 288,627	$ 291,761

9) OIL AND NATURAL GAS SALES

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2014	2013	2014	2013
Oil and natural gas sales	$ 504,551	$ 404,827	$ 999,575	$ 778,252
Royalties[1]	(89,626)	(63,503)	(176,910)	(123,547)
Oil and natural gas sales, net of royalties	$ 414,925	$ 341,324	$ 822,665	$ 654,705

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

10) GENERAL AND ADMINISTRATIVE EXPENSE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2014	2013	2014	2013
General and administrative expense	$ 18,672	$ 18,804	$ 39,201	$ 43,483
Share-based compensation expense[1]	9,508	5,862	18,102	12,392
General and administrative expense	$ 28,180	$ 24,666	$ 57,303	$ 55,875

(1) Share-based compensation relates to the cash and equity-settled Long-term Incentive Plans and the Stock Option Plan. Refer to Note 14(c) for further discussion.

11) INTEREST EXPENSE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2014	2013	2014	2013
Realized:				
Interest on bank debt and senior notes	$ 15,962	$ 14,291	$ 30,628	$ 28,477
Unrealized:				
Cross currency interest rate swap (gain)/loss	313	488	580	820
Interest rate swap (gain)/loss	–	(171)	–	(437)
Amortization of debt issue costs	247	192	493	377
Interest expense	$ 16,522	$ 14,800	$ 31,701	$ 29,237

12) FOREIGN EXCHANGE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2014	2013	2014	2013
Realized:				
Foreign exchange (gain)/loss	$ 16,626	$ 14,867	$ 16,676	$ 17,599
Unrealized:				
Translation of U.S. dollar debt and working capital (gain)/loss	(9,052)	12,218	1,935	16,538
Cross currency interest rate swap (gain)/loss	(14,885)	(18,970)	(16,130)	(19,982)
Foreign exchange derivative (gain)/loss	86	(5,931)	(8,237)	(7,619)
Foreign exchange (gain)/loss	$ (7,225)	$ 2,184	$ (5,756)	$ 6,536

13) INCOME TAXES

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2014	2013	2014	2013
Current tax expense/(recovery)				
Canada	$ (190)	$ 77	$ (374)	$ 81
U.S.	3,987	1,324	11,849	2,627
Current tax expense/(recovery)	3,797	1,401	11,475	2,708
Deferred tax expense/(recovery)				
Canada	$ (7,005)	$ 9,957	$ (5,318)	$ (2,512)
U.S.	19,712	10,327	42,528	24,700
Deferred tax expense/(recovery)	$ 12,707	$ 20,284	$ 37,210	$ 22,188
Income tax expense/(recovery)	$ 16,504	$ 21,685	$ 48,685	$ 24,896

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.

14) SHAREHOLDERS' EQUITY

a) Share Capital

	Six months ended June 30, 2014		Year ended December 31, 2013	
Authorized unlimited number of common shares **Issued:** (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	202,758	$ 3,061,839	198,684	$ 2,997,682
Issued for cash:				
Stock Option Plan	1,165	19,193	1,042	14,838
Non-cash:				
Stock Option Plan	–	3,683	–	3,108
Stock Dividend Plan	845	17,487	3,032	46,211
Balance, end of period	204,768	$ 3,102,202	202,758	$ 3,061,839

b) Dividends

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2014**	**2013**	**2014**	**2013**
Cash dividends	$ 50,508	$ 42,620	$ 92,662	$ 86,299
Stock dividends	4,706	11,389	17,487	21,495
Dividends to shareholders	$ 55,214	$ 54,009	$ 110,149	$ 107,794

c) Share-based compensation ("SBC")

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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2014**	**2013**	**2014**	**2013**
Cash:				
Long-term incentive plans expense	$ 10,648	$ 3,687	$ 17,512	$ 9,205
Non-Cash:				
Long-term incentive plans expense	2,856	–	3,691	–
Stock option plan expense	686	2,951	2,803	5,478
Equity swap (gain)/loss	(4,682)	(776)	(5,904)	(2,291)
Share-based compensation expense	$ 9,508	$ 5,862	$ 18,102	$ 12,392

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

In 2014, the Performance Share Unit and Restricted Share Unit 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 Performance Share Unit ("PSU"), Restricted Share Unit ("RSU") and Director Share Unit ("DSU") activity for the six months ended June 30, 2014:

For the six months ended June 30, 2014 (thousands of units)	PSU	RSU	DSU	Total
Balance, beginning of year	650	821	99	1,570
Granted	543	811	47	1,401
Vested	–	(305)	–	(305)
Forfeited	(16)	(40)	–	(56)
Balance, end of period	1,177	1,287	146	2,610
End of period balances, by grant settlement type:				
Cash-settled units	637	498	146	1,281
Equity-settled units	540	789	–	1,329
Balance, end of period	1,177	1,287	146	2,610

Cash-settled LTI Plans

For the three and six months ended June 30, 2014 the Company recorded cash SBC expense of $10.6 million and $17.5 million, respectively (June 30, 2013 – $3.7 million and $9.2 million) and for the three and six months ended June 30, 2014, made $0.3 million and $11.8 million, respectively in cash payments related to its cash-settled plans (June 30, 2013 – $0.4 million and $6.9 million).

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

At June 30, 2014 ($ thousands, except for years)	PSU(1)	RSU	DSU	Total
Cumulative recognized SBC expense	$ 21,641	$ 10,527	$ 4,161	$ 36,329
Unrecognized SBC expense	11,689	4,025	–	15,714
Intrinsic value	$ 33,330	$ 14,552	$ 4,161	$ 52,043
Weighted-average remaining contractual term (years)	1.1	0.9	–	

(1) Includes estimated performance multipliers.

Equity-settled LTI Plans

With equity-settled LTI awards being settled through the issuance of treasury shares, the related SBC expense is recorded as a non-cash amount on the Consolidated Statements of Income/(Loss), with an offset recorded to Paid-in Capital. On settlement, the amount previously recorded to Paid-in Capital is reclassified to Share Capital.

For the three and six months ended June 30, 2014 the Company recorded non-cash SBC expense of $2.9 million and $3.7 million, respectively. No non-cash amounts were recognized for the three and six months ended June 30, 2013 with respect to the equity-settled grants.

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

At June 30, 2014 ($ thousands, except for years)	PSU(1)	RSU	Total
Cumulative recognized SBC expense	$ 881	$ 2,810	$ 3,691
Unrecognized SBC expense	6,860	10,916	17,776
	$ 7,741	$ 13,726	$ 21,467
Weighted-average remaining contractual term (years)	2.5	1.7	

(1) Includes estimated performance multipliers.

(ii) Stock Option Plan

The Company did not grant any stock options during the six months ended June 30, 2014. Activity for the respective reporting periods is as follows:

	Six months ended June 30, 2014	
	Number of Options (thousands)	Weighted Average Exercise Price
Options outstanding		
Beginning of year	13,414	$ 18.65
Granted	–	–
Exercised	(1,165)	16.48
Forfeited	(396)	20.28
Expired	–	–
Options outstanding, end of period	11,853	$ 18.81
Options exercisable at the end of period	6,136	$ 21.97

At June 30, 2014, 6,136,000 options were exercisable at a weighted average reduced exercise price of $21.97 with a weighted average remaining contractual term of 4.2 years, giving an intrinsic value of $36.7 million (June 30, 2013 – $1.4 million). The intrinsic value of options exercised during the three and six months ended June 30, 2014 was $5.2 million and $8.1 million, respectively (June 30, 2013 – $nil and $nil).

At June 30, 2014 the unrecognized SBC expense related to non-vested options was $2.5 million (June 30, 2013 – $8.2 million). The expense is expected to be fully recognized over a weighted-average period of 1.1 years.

d) Paid-in Capital

The following table summarizes the paid-in capital activity for the six months ended June 30, 2014 and the year ended December 31, 2013:

($ thousands)	Six months ended June 30, 2014	Year ended December 31, 2013
Balance, beginning of year	$ 38,398	$ 32,293
Stock Option Plan – exercised	(3,683)	(3,108)
Share-based compensation – non-cash	6,494	9,213
Balance, end of period	$ 41,209	$ 38,398

e) Basic and Diluted Earnings Per Share

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

	Three months ended June 30,		Six months ended June 30,	
(thousands, except per share amounts)	2014	2013	2014	2013
Net income/(loss)	$ 39,957	$ 38,467	$ 79,994	$ 22,070
Weighted average shares outstanding – Basic	204,158	199,825	203,671	199,430
Dilutive impact of share-based compensation	4,364	294	3,892	156
Weighted average shares outstanding – Diluted	208,522	200,119	207,563	199,586
Net income/(loss) per share				
Basic	0.20	0.19	0.39	0.11
Diluted	0.19	0.19	0.39	0.11

15) FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) Fair Value Measurements

At June 30, 2014, the carrying value of cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value due to the short-term maturity of the instruments.

At June 30, 2014 senior notes included in long-term debt had a carrying value of $776.3 million and a fair value of $806.6 million (December 31, 2013 – $810.9 million and $837.8 million, respectively).

Enerplus' derivative financial instruments are classified as Level 2. A Level 2 classification is appropriate where observable inputs other than quoted market prices are used in the fair value determination.

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

b) Derivative Financial Instruments

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

The following table summarizes the change in fair value for the three and six months ended June 30, 2014 and 2013:

	Three months ended June 30,		Six months ended June 30,		
Gain/(Loss) ($ thousands)	**2014**	**2013**	**2014**	**2013**	**Income Statement Presentation**
Interest Rate Swaps	$ –	$ 171	$ –	$ 436	Interest
Cross Currency Interest Rate Swap:					
Interest	(313)	(488)	(580)	(820)	Interest
Foreign Exchange	14,885	18,970	16,130	19,982	Foreign Exchange
Foreign Exchange Derivatives	(86)	5,931	8,237	7,619	Foreign Exchange
Electricity Swaps	228	1,061	182	1,470	Operating
Equity Swaps	4,682	776	5,904	2,291	General and Administrative
Commodity Derivative Instruments:					
Oil	(24,810)	8,685	(34,203)	(20,892)	Commodity derivative
Gas	5,284	12,837	(2,609)	3,803	instruments Gain/(loss)
Total	$ (130)	$ 47,943	$ (6,939)	$ 13,889	

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

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	**2014**	**2013**	**2014**	**2013**
Change in fair value gain/(loss)	$ (19,526)	$ 21,522	$ (36,812)	$ (17,089)
Net realized cash gain/(loss)	(24,543)	9,100	(39,854)	20,656
Commodity derivative instruments gain/(loss)	$ (44,069)	$ 30,622	$ (76,666)	$ 3,567

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

($ thousands)	June 30, 2014 Assets Current	June 30, 2014 Assets Long-term	June 30, 2014 Liabilities Current	December 31, 2013 Assets Current	December 31, 2013 Assets Long-term	December 31, 2013 Liabilities Current
Cross Currency Interest Rate Swap	$ –	$ –	$ –	$ –	$ –	$ 15,548
Foreign Exchange Derivatives	4,275	19,661	–	564	15,135	–
Electricity Swaps	91	–	–	–	–	95
Equity Swaps	5,500	6,265	–	1,723	4,139	–
Commodity Derivative Instruments:						
Oil	1,378	–	50,412	4,138	–	18,970
Gas	6,290	–	8,544	2,773	–	2,418
Total	$ 17,534	$ 25,926	$ 58,956	$ 9,198	$ 19,274	$ 37,031

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 Enerplus' price risk management positions at July 23, 2014:

Crude Oil Instruments:

Instrument Type	bbls/day	US$/bbl[1]
Jul 1, 2014 – Sep 30, 2014		
WTI Swap	22,000	95.54
WCS Differential Swap	3,000	– 21.00
Brent – WTI Ratio Spread (% of Brent Price)	3,000	92.63%
Oct 1, 2014 – Dec 31, 2014		
WTI Swap	20,000	95.29
WCS Differential Swap	4,000	– 21.00
Brent – WTI Ratio Spread (% of Brent Price)	3,000	92.63%
Jan 1, 2015 – Jun 30, 2015		
WTI Swap	15,500	93.58
Jul 1, 2015 – Dec 31, 2015		
WTI Swap	8,000	93.86

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

Natural Gas Instruments:

Instrument Type	MMcf/day	CDN$/Mcf	US$/Mcf
Jul 1, 2014 – Dec 31, 2014			
AECO Swap	28.4	4.25	
Jul 1, 2014 – Dec 31, 2014			
NYMEX Swap	75.0		4.14
NYMEX Purchased Put	30.0		4.30
NYMEX Purchased Call	25.0		4.17
NYMEX Sold Put	25.0		3.23
NYMEX Sold Call	55.0		5.04
Jan 1, 2015 – Mar 31, 2015			
NYMEX Swap	65.0		4.31
NYMEX Purchased Put	30.0		4.53
NYMEX Sold Call	30.0		5.53
Apr 1, 2015 – Jun 30, 2015			
NYMEX Swap	65.0		4.31
Jul 1, 2015 – Dec 31, 2015			
NYMEX Swap	45.0		4.21

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Jul 1, 2014 – Dec 31, 2014		
AESO Power Swap	16.0	53.33
Jan 1, 2015 – Dec 31, 2015		
AESO Power Swap	16.0	50.79
Jan 1, 2016 – Dec 31, 2016		
AESO Power Swap	3.0	50.50

Physical Contracts:

Instrument Type	MMcf/day	US$/Mcf
Jul 1, 2014 – Oct 31, 2014		
AECO-NYMEX Basis	60.0	(0.61)
Nov 1, 2014 – Oct 31, 2015		
AECO-NYMEX Basis	50.0	(0.66)
Nov 1, 2015 – Oct 31, 2016		
AECO-NYMEX Basis	60.0	(0.67)
Nov 1, 2016 – Oct 31, 2017		
AECO-NYMEX Basis	70.0	(0.64)
Nov 1, 2017 – Oct 31, 2018		
AECO-NYMEX Basis	70.0	(0.64)

Foreign Exchange Risk:

Enerplus is exposed to foreign exchange risk in relation to its U.S. operations, and U.S. dollar denominated senior notes and working capital. Additionally, Enerplus' crude oil sales and a portion of its natural gas sales are based on U.S. dollar indices. Enerplus manages currency risk relating to its senior notes through the derivative instruments detailed below.

Foreign Exchange Derivatives:

During the six months ended June 30, 2014, Enerplus entered into foreign exchange collars to hedge a portion of its foreign exchange exposure on U.S. dollar denominated oil and gas sales. The following contracts are outstanding at July 23, 2014:

Instrument Type(1)	Monthly Notional Amount (US$ millions)	Floor	Ceiling	Conditional Ceiling(2)
Jun 1, 2014 – Dec 31, 2014	12.0	1.1046	1.1558	1.1198
Jan 1, 2015 – Dec 31, 2015	12.0	1.1083	1.1900	1.1254

(1) Transactions with a common term have been aggregated and presented at average USD/CDN foreign exchange rates.
(2) If the USD/CDN average monthly rate settles above the ceiling rate the settlement amount is determined based on the conditional ceiling.

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. At June 30, 2014, following the third settlement, Enerplus had US$21.6 million of remaining notional debt swapped. These foreign exchange swaps mature between October 2014 and October 2015 in conjunction with the remaining principal repayments on the US$54.0 million senior notes.

During 2011 Enerplus entered into foreign exchange swaps on US$175.0 million of notional debt at approximately par. These foreign exchange swaps mature between June 2017 and June 2021 in conjunction with the principal repayments on the US$225.0 million senior notes.

Interest Rate Risk:

At June 30, 2014, approximately 72% of Enerplus' debt was based on fixed interest rates and 28% was based on floating interest rates. At June 30, 2014 Enerplus did not have any interest rate derivatives outstanding.

Equity Price Risk:

Enerplus is exposed to equity price risk in relation to its cash settled long-term incentive plans detailed in Note 14.

Enerplus has entered into various equity swaps maturing between 2013 and 2016 and has effectively fixed the future settlement cost on 995,000 shares at a weighted average price of $14.78 per share.

(ii) Credit Risk

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

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

Enerplus' maximum credit exposure at the balance sheet date consists of the carrying amount of its non-derivative financial assets and the fair value of its derivative financial assets. At June 30, 2014 approximately 73% of Enerplus' marketing receivables were with companies considered investment grade.

At June 30, 2014 approximately $1.1 million or 0.5% 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 off future payments or seeking other remedies including legal action. Should Enerplus determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If Enerplus subsequently determines an account is uncollectible the account is written off with a corresponding charge to the allowance account. Enerplus' allowance for doubtful accounts balance at June 30, 2014 was $2.8 million (December 31, 2013 – $2.8 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.

16) CONTINGENCIES AND COMMITMENTS

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 interim 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.

During the quarter, Enerplus entered into an agreement to extend its Calgary head office lease for an additional 5 years through 2024, which including operating costs, is expected to amount to approximately $57 million over the additional term.

17) SUPPLEMENTAL CASH FLOW INFORMATION

a) Changes in Non-Cash Operating Working Capital

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2014	2013	2014	2013
Accounts receivable	$ 12,292	$ (11,365)	$ (19,877)	$ (15,197)
Other current assets	(379)	(202)	544	(1,189)
Accounts payable	7,622	5,242	(36,942)	2,074
	$ 19,535	$ (6,325)	$ (56,275)	$ (14,312)

b) Other

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2014	2013	2014	2013
Income taxes paid/(received)	$ 18,521	$ 356	$ 18,387	$ (4,890)
Interest paid	$ 26,305	$ 26,347	$ 28,688	$ 29,221

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Calgary, Alberta

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Corporate Director
Canmore, Alberta

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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) Chairman of the Corporate Governance & Nominating Committee
(5) Member of the Audit & Risk Management Committee
(6) Chairman of the Audit & Risk Management Committee
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(8) Chairman of the Reserves Committee
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(10) Chairman of the Compensation & Human Resources Committee
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(12) Chairman of the Safety & Social Responsibility Committee

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ENERPLUS CORPORATION

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Senior Vice President, Operations

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P. Scott Walsh
Vice President, Information & Corporate Services

Kenneth W. Young
Vice President, Land

Michael R. Politeski
Treasurer & Corporate Controller

CORPORATE INFORMATION

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Enerplus Resources (USA) Corporation

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ABBREVIATIONS

AECO	a reference to the physical storage and trading hub on the TransCanada Alberta Transmission System (NOVA) which is the delivery point for the various benchmark Alberta Index prices
bbl(s)/day	barrel(s) per day, with each barrel representing 34.972 Imperial gallons or 42 U.S.gallons
Bcf	billion cubic feet
Bcfe	billion cubic feet equivalent
BOE	barrels of oil equivalent
Brent	crude oil sourced from the North Sea, the benchmark for global oil trading quoted in $US dollars.
LTI	long-term incentive
Mbbls	thousand barrels
MBOE	thousand barrels of oil equivalent
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMbbl(s)	million barrels
MMBOE	million barrels of oil equivalent
MMBtu	million British Thermal Units
MMcf	million cubic feet
MSW	mixed sweet blend
MWh	megawatt hour(s) of electricity
NGLs	natural gas liquids
NYMEX	New York Mercantile Exchange, the benchmark for North American natural gas pricing
OCI	other comprehensive income
SBC	share based compensation
SDP	stock dividend program
U.S. GAAP	accounting principles generally accepted in the United States of America
WCS	Western Canadian Select at Hardisty, Alberta, the benchmark for Western Canadian heavy oil pricing purposes
WTI	West Texas Intermediate oil at Cushing, Oklahoma, the benchmark for North American crude oil pricing

Why invest in Enerplus?

Enerplus is a North American energy producer with a diversified asset base of high-quality, low-decline oil and gas assets complemented by growth assets in resource plays with superior economics. We are focused on creating value for our investors through the successful development of our properties and the disciplined management of our balance sheet. Through our activities, we strive to provide investors with a competitive return comprised of both growth and income.

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