Q2/13

ENERPLUS SECOND QUARTER REPORT
SIX MONTHS ENDED JUNE 30, 2013

SELECTED FINANCIAL RESULTS	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Financial (000's)				
Funds Flow	$ 204,706	$ 146,547	$ 377,302	$ 309,253
Cash and Stock Dividends	54,009	88,599	107,794	194,594
Net Income	52,622	100,264	47,384	66,443
Debt Outstanding – net of cash	1,133,048	1,152,746	1,133,048	1,152,746
Capital Spending	139,644	208,587	312,588	525,653
Property and Land Acquisitions	51,692	23,649	55,659	56,669
Property Dispositions	71,293	(87)	72,624	52,524
Debt to Trailing 12 Month Funds Flow	1.6x	2.0x	1.6x	2.0x
Financial per Weighted Average Shares Outstanding				
Funds Flow	$ 1.02	$ 0.74	$ 1.89	$ 1.60
Net Income	0.26	0.51	0.24	0.34
Weighted Average Number of Shares Outstanding (000's)	199,825	196,768	199,430	193,306
Selected Financial Results per BOE(1)				
Oil & Gas Sales(2)	$ 48.65	$ 42.07	$ 47.68	$ 44.51
Royalties	(9.93)	(8.36)	(9.73)	(8.80)
Commodity Derivative Instruments	1.11	0.68	1.29	(0.38)
Operating Costs	(10.55)	(10.80)	(10.48)	(10.32)
General and Administrative	(2.29)	(2.76)	(2.71)	(2.82)
Equity Based Compensation	(0.45)	0.19	(0.57)	(0.01)
Interest and Other Expenses	(1.38)	(0.90)	(1.78)	(0.81)
Taxes	(0.18)	(0.51)	(0.18)	(0.31)
Funds Flow	**$ 24.98**	**$ 19.61**	**$ 23.52**	**$ 21.06**

SELECTED OPERATING RESULTS	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Average Daily Production				
Crude oil (bbls/day)	38,066	36,527	38,193	35,300
NGLs (bbls/day)	3,497	3,393	3,546	3,698
Natural gas (Mcf/day)	290,841	253,126	281,275	249,905
Total (BOE/day)	90,037	82,108	88,618	80,649
% Crude Oil & Natural Gas Liquids	46%	49%	47%	48%
Average Selling Price(2)				
Crude oil (per bbl)	$ 82.95	$ 74.36	$ 80.74	$ 79.93
NGLs (per bbl)	45.64	60.11	52.16	58.30
Natural gas (per Mcf)	3.70	2.06	3.41	2.17
Net Wells drilled	10	19	35	53

(1) Non-cash amounts have been excluded.
(2) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Average Benchmark Pricing				
WTI crude oil (US$/bbl)	$ 94.22	$ 93.49	$ 94.30	$ 98.21
AECO – monthly index (CDN$/Mcf)	3.59	1.83	3.34	2.18
AECO – daily index (CDN$/Mcf)	3.53	1.90	3.37	2.02
NYMEX – monthly NX3 index (US$/Mcf)	4.09	2.26	3.72	2.52
USD/CDN exchange rate	1.02	1.01	1.02	1.01

Share Trading Summary **For the three months ended June 30, 2013**	**CDN* – ERF** (CDN$)	**U.S.** – ERF** (US$)
High	$ 16.95	$ 16.47
Low	$ 12.93	$ 12.60
Close	$ 15.54	$ 14.79

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

2013 Dividends per Share **Payment Month**	**CDN$**	**US$(1)**
First Quarter Total	$ 0.27	$ 0.27
April	$ 0.09	$ 0.09
May	$ 0.09	$ 0.09
June	$ 0.09	$ 0.08
Second Quarter Total	$ 0.27	$ 0.26
Total Year-to-Date	$ 0.54	$ 0.53

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

President’s Message

During the second quarter of 2013, our operations in both Canada and the U.S. continued to perform ahead of our expectations. Daily production was up 10% over the second quarter of 2012 and 3% higher than the first quarter of 2013, averaging 90,037 BOE/day. The most significant increases were in our natural gas assets in both Canada and the U.S. as a result of successful drilling activity in the Wilrich and continued strong performance in the Marcellus. For the first six months of 2013, daily production has averaged 88,618 BOE/day, significantly ahead of our expectations.

We continued to improve the profitability of our operations through disciplined cost management and capital spending. Drilling and development activities in Canada slowed during the quarter, resulting in a 20% decrease in capital spending compared to the first quarter of 2013. Approximately $140 million was invested across our portfolio with over 80% of our spending dedicated to our oil properties in both Canada and the U.S. In the first half of 2013, we’ve invested approximately $313 million in development capital which is about 45% of our full year budget. Our North Dakota operations continued to attract the majority of our capital investment given the strong economic returns from this region. Operating costs and general and administrative costs also continue to track with guidance.

As a result of higher production, improved capital efficiencies and an improvement in our netback, the sustainability of our business has continued to improve. Funds flow increased by almost 20% during the quarter to approximately $205 million, more than covering our capital spending and dividends. Our adjusted payout ratio decreased to 89% in the quarter, and on a year-to-date basis, is approximately 106% before considering the proceeds of our divestment activities. As a result of non-core asset sales and the increase in funds flow, our trailing 12 month debt-to-funds flow ratio also improved, falling to 1.6 times at the end of the quarter.

Our hedging program continues to be an important element in reducing the risk to our funds flow and has generated approximately $21 million year-to-date in cash gains. As the majority of our funds flow comes from crude oil revenues, we continue to enter into additional WTI hedge positions in order to provide greater certainty of our future funds flow. We now have 75% of our remaining 2013 crude oil production, after royalties, hedged at a price of US$100.35 per barrel and we have 56% of our expected 2014 crude oil production volumes, net of royalties, hedged at an average price of US$93.06 per barrel. We also have 32% of our remaining 2013 natural gas volumes, after royalties, hedged at an average price of $3.51 per Mcf. For 2014, we have 24% of our expected net natural gas production hedged against the NYMEX benchmark at a price of US$4.17 per Mcf with an additional 2% hedged against the AECO benchmark at a price of $3.85 per Mcf.

We have also continued to consolidate our portfolio. We increased the concentration in our Canadian waterflood portfolio through the acquisition of an additional 50% working interest in the Pouce Coupe Boundary Lake light oil pool in Alberta for approximately $34 million, after adjustments. As previously announced, we have also either sold or entered into agreements to sell approximately 1,300 BOE/day of non-core producing assets, net of acquisitions. In addition, we have also closed the sale of infrastructure assets in the Fort Berthold region for approximately $34 million. Year-to-date, including agreements signed, we have sold approximately $192 million in non-core assets and invested approximately $55 million in acquisitions in our core areas.

As a result of lower drilling activity during the second quarter and planned turn-around activity, along with the impact of non-core property divestments, we expect to see a decline in production volumes during the third quarter. Although production has exceeded expectations year-to-date, we are not increasing our annual average production guidance beyond 85,000 BOE/day given our plans to continue to rationalize additional assets over the course of the year. If we are unable to complete additional divestments, we would expect our annual average and exit production to potentially exceed our current guidance. As the majority of the sales completed to date have been crude oil properties and with the growth in our natural gas production from our core assets, we now expect our crude oil and liquids production will represent approximately 48% of our total volumes in 2013.

Production and Capital Spending

	Three months ended June 30, 2013		Six months ended June 30, 2013	
	Average Production Volumes	Capital Spending ($ millions)	Average Production Volumes	Capital Spending ($ millions)
Crude Oil & NGLs (BOE/day)				
Canada	21,339	$ 35	21,809	$ 82
United States	20,224	78	19,930	155
Total Crude Oil & NGLs (BOE/day)	41,563	$ 113	41,739	$ 237
Natural Gas (Mcf/day)				
Canada	186,569	$ 10	182,214	$ 46
United States	104,272	17	99,061	30
Total Natural Gas (Mcf/day)	290,841	$ 27	281,275	$ 76
Company Total (BOE/day)	90,037	$ 140	88,618	$ 313

Net Drilling Activity – for the three months ended June 30, 2013

	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in*	Wells On-stream**	Dry & Abandoned Wells
Crude Oil						
Canada	3.6	–	3.6	3.6	8.6	–
United States	4.7	–	4.7	1.5	6.1	–
Total Crude Oil	**8.3**	**–**	**8.3**	**5.1**	**14.7**	**–**
Natural Gas						
Canada	–	–	–	–	1.1	–
United States	2.1	–	2.1	2.1	1.8	–
Total Natural Gas	**2.1**	**–**	**2.1**	**2.1**	**2.9**	**–**
Company Total	**10.4**	**–**	**10.4**	**7.2**	**17.6**	**–**

* Wells drilled during the quarter that are pending potential completion/tie-in or abandonment as at June 30, 2013.
** Total wells brought on-stream during the quarter regardless of when they were drilled.

U.S. Crude Oil

Production from our U.S. crude oil assets increased slightly during the second quarter primarily due to drilling activity at Fort Berthold, North Dakota. We invested approximately $78 million drilling 4.7 net long horizontal wells and bringing 6.1 net horizontal wells on-stream with the majority of the wells brought on late in the quarter. Service and supply costs continue to be lower than our original expectations with a 10% savings realized on well costs year-to-date. Production from Fort Berthold continues to be on track with our expectations and averaged just over 15,000 BOE/day during the quarter.

Canadian Crude Oil

Production from our Canadian crude oil properties was down slightly from the first quarter, averaging approximately 21,300 BOE/day due to a slow down in development activity and the sale of non-core production. The majority of our activities were focused on drilling additional producing wells in our waterflood properties at Medicine Hat and Giltedge. We also acquired an incremental 50% working interest in the Pouce Coupe South Boundary Lake waterflood property during the quarter, taking our working interest to approximately 100%. This property has a very low historical decline rate of roughly 5% with an average netback of approximately $50/BOE and we believe there is future upside potential through incremental drilling and waterflood optimization.

U.S. Natural Gas

U.S. natural gas production grew by more than 10% during the quarter, averaging approximately 104 MMcf/day. The majority of our U.S. gas production is from the Marcellus region in northeast Pennsylvania which produced on average 88 MMcf/day of natural gas during the quarter, up 11% from the first quarter. We continue to see strong well performance, particularly in the Bradford and Susquehanna areas where approximately 90% of our Marcellus capital is being allocated. As a result of the growth in production volumes and increasing natural gas prices, we have seen a significant increase in funds flow from our Marcellus operations in 2013 generating approximately $34 million in funds flow year-to-date which has fully funded our capital spending to date in this region.

Canadian Natural Gas

Based upon the success of our drilling activity to date in the Wilrich, we plan to drill two additional horizontal development wells in the Ansell area in the latter half of the year with an expected on-stream early in 2014. We also plan to begin drilling two Montney horizontal wells at our Cameron/Julienne property in northeast British Columbia in the fourth quarter. The first of two vertical wells testing the Duvernay is currently underway. We expect to finish drilling both of these wells in the fourth quarter of 2013.

U.S. Filing Status

As a result of the increase in value of our U.S. assets combined with the majority of our shareholders residing in the U.S., effective January 1, 2014, we anticipate that Enerplus will no longer qualify as a "foreign private issuer" under U.S. securities regulations. Enerplus would then be considered a U.S. domestic issuer and would become subject to U.S. domestic reporting requirements from that date forward. The change in filing status would not impact our operations, but would change the way in which we report and file our operating and financial results. For example, our financial statements would be prepared under U.S. Generally Accepted Accounting Principles. We do not expect a material change in most of our key performance indicators such as funds flow, debt levels, capital spending, operating costs, G&A expenses, netbacks or adjusted payout ratio. Sales revenues and production volumes would be reported on a net (after royalty) basis however we will also provide supplementary disclosures for gross sales revenue and volumes to facilitate comparison with Canadian peers. In addition to filing our reserves under Canadian National Instrument 51-101 standards, our reserves information would also be prepared and filed under the U.S. SEC standards.

Summary

Enerplus has undergone significant change in our portfolio and strategy over the past few years. The impact of these changes is being reflected in our improved operational performance. Based upon our results for the first half of 2013 and including the non-core asset sales we've made year-to-date, we expect to meet or beat our guidance this year. We've achieved significant growth in production and funds flow and our balance sheet remains strong. As a result of this performance, we are delivering profitable growth and income to our investors.

Ian C. Dundas
President & Chief Executive Officer

Management's Discussion and Analysis

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

The following discussion and analysis of financial results is dated August 8, 2013 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, 2013 and 2012 (the "Interim Financial Statements"),
- the audited consolidated financial statements of Enerplus as at and for the years ended December 31, 2012 and 2011 (the "Financial Statements"); and
- the MD&A of Enerplus for the year ended December 31, 2012 (the "Annual MD&A").

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Interim Financial Statements. Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE and oil and natural gas liquids ("NGL") have been converted to thousand cubic feet of gas equivalent ("Mcfe") based on 0.167 bbl:1 Mcfe. The BOE and Mcfe rates are based on an energy equivalent conversion method primarily applicable at the burner tip and do not represent a value equivalent at the wellhead. Given that the value ratio based on the current price of natural gas as compared to crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value. Use of BOE and Mcfe in isolation may be misleading. All production volumes are presented on a company interest basis, being the Company's working interest share before deduction of any royalties paid to others plus the Company's royalty interests. 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 discussion at the end of the MD&A under "Forward-Looking Information and Statements" for further information.

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 International Financial Reporting Standards ("IFRS") and therefore may not be comparable with the calculation of similar measures by other entities:

"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 dividends and the Company's former Dividend Reinvestment Plan ("DRIP") proceeds, plus capital spending (including office capital) divided by funds flow.

"Netback" is used to evaluate operating performance of our crude oil and natural gas assets. The term netback is calculated as oil and gas sales revenue (net of transportation), less royalties and operating costs.

OVERVIEW

Our strong operational performance continued during the second quarter. Production levels increased to 90,037 BOE/day, which is an increase of 10% year over year and 3% from the first quarter of 2013. Our capital program is on track with spending of $139.7 million during the quarter, with approximately 80% of this spending being directed towards our crude oil properties. Operating expenses of $10.42/BOE and general and administrative expenses ("G&A") of $2.29/BOE were in-line with our expectations.

Funds flow for the second quarter totaled $204.7 million, an increase of $58.2 million or 40% from the second quarter of 2012 and an increase of $32.1 million or 19% from the first quarter of 2013. Funds flow continued to strengthen with higher production volumes and improved realized crude oil and natural gas prices. Net income for the quarter totaled $52.6 million, down from $100.3 million in the second quarter of 2012 due to lower non-cash mark-to-market gains on commodity derivative instruments.

We continued to sell non-core properties in order to focus our asset portfolio. During the quarter we raised proceeds of $71.3 million through non-core asset sales. Subsequent to the quarter, we have signed agreements for additional non-core asset dispositions for proceeds of approximately $119.7 million, bringing our year-to-date expected proceeds to approximately $192.3 million. These divestments have also helped to maintain our balance sheet strength and sustainability.

Our adjusted payout ratio continued to improve, decreasing to 89% in the second quarter of 2013. This improvement is due to an increase in our funds flow as well as lower capital spending. At June 30, 2013, we had a conservative trailing twelve month debt to funds flow ratio of 1.6x and approximately $670.0 million of available capacity on our bank credit facility.

Based on our strong year-to-date operational performance we are continuing to maintain all of our operational guidance measures. Although production has exceeded expectations year-to-date, we are not increasing our annual average production guidance beyond 85,000 BOE/day given our plans for additional divestments over the remainder of the year. We also expect that our annual cash based equity compensation expenses will increase from $0.45/BOE to $0.60/BOE given our current share performance.

Production

Production increased to 90,037 BOE/day in the second quarter of 2013 from 87,183 BOE/day in the first quarter of 2013. In comparison to the second quarter of 2012, production increased by 10% or 7,929 BOE/day. Crude oil volumes were up by 4% due to increased production from our Fort Berthold property and natural gas volumes increased by 15% due to increased production from our Marcellus and Wilrich assets.

With the continued strength in our natural gas production and our oil weighted non-core divestments, our weighting of crude oil and liquids production decreased to 46% of our total production in the second quarter of 2013. We are now expecting our crude oil and liquids weighting to average 48% for 2013.

Average daily production volumes for the three and six months ended June 30, 2013 and 2012 are outlined below:

	Three months ended June 30,			Six months ended June 30,		
Average Daily Production Volumes	**2013**	**2012**	**% Change**	**2013**	**2012**	**% Change**
Crude oil (bbls/day)	38,066	36,527	4%	38,193	35,300	8%
Natural gas liquids (bbls/day)	3,497	3,393	3%	3,546	3,698	(4)%
Natural gas (Mcf/day)	290,841	253,126	15%	281,275	249,905	13%
Total daily sales (BOE/day)	90,037	82,108	10%	88,618	80,649	10%

We expect production levels will decline in the third quarter given the reduction in our drilling activity in the second quarter, expected plant maintenance, and the impact of divestments. Although production has exceeded expectations year-to-date, we are not increasing our annual average production guidance beyond 85,000 BOE/day given our plans to continue to rationalize additional assets over the remainder of the year. If we are unable to complete additional divestments, our annual average and exit production could potentially exceed our current guidance.

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 quarterly average prices from the second quarter of 2012 to the second quarter of 2013.

	Six months ended June 30						
Pricing (average for the period)	**2013**	**2012**	**Q2 2013**	**Q1 2013**	**Q4 2012**	**Q3 2012**	**Q2 2012**
Benchmarks							
WTI crude oil (US$/bbl)	$ 94.30	$ 98.21	$ 94.22	$ 94.37	$ 88.18	$ 92.22	$ 93.49
AECO – monthly index (CDN$/Mcf)	3.34	2.18	3.59	3.08	3.06	2.19	1.83
AECO – daily index (CDN$/Mcf)	3.37	2.02	3.53	3.20	3.22	2.29	1.90
NYMEX – monthly NX3 (US$/Mcf)	3.72	2.52	4.09	3.35	3.36	2.81	2.26
US/CDN exchange rate	1.02	1.01	1.02	1.01	0.99	1.00	1.01
Enerplus selling price(1)							
Crude oil (per bbl)	$ 80.74	$ 79.93	$ 82.95	$ 78.52	$ 76.75	$ 76.41	$ 74.36
Natural gas liquids (per bbl)	52.16	58.30	45.64	58.58	47.31	47.81	60.11
Natural gas (per Mcf)	3.41	2.17	3.70	3.10	3.01	2.20	2.06
Average differentials (US$/bbl or US$/Mcf)							
MSW Edmonton – WTI	$ (5.31)	$ (10.30)	$ (3.67)	$ (6.95)	$ (3.32)	$ (7.21)	$ (10.12)
WCS Hardisty – WTI	(25.56)	(22.14)	(19.16)	(31.96)	(18.11)	(21.72)	(22.87)
Brent Futures (ICE) – WTI	13.69	15.39	9.14	18.24	21.81	17.22	15.38
AECO monthly – NYMEX	(0.43)	(0.28)	(0.58)	(0.28)	(0.31)	(0.60)	(0.40)
Enerplus realized differentials(1)							
U.S. crude oil – WTI	$ (7.89)	$ (14.79)	$ (9.61)	$ (6.10)	$ (5.18)	$ (12.90)	$ (13.21)
Canada crude oil – WTI	(22.03)	(21.45)	(16.97)	(26.97)	(15.54)	(17.41)	(23.48)
U.S. natural gas – NYMEX	0.12	0.35	0.08	0.12	0.34	0.34	0.41
Canada natural gas – NYMEX	(0.62)	(0.52)	(0.78)	(0.49)	(0.57)	(0.86)	(0.34)

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

Crude Oil and Natural Gas Liquids

Crude oil prices remained range-bound during the second quarter of 2013 with WTI prices typically trading between US$87/bbl and US$97/bbl. Overall, the average price was relatively unchanged from the first quarter of 2013 at US$94.22/bbl. Globally, Brent prices weakened relative to the WTI benchmark, with the Brent – WTI spread narrowing from US$18.24/bbl during the first quarter to US$9.14/bbl during the second quarter. WTI prices have been supported by the startup of new pipeline projects which have eased the transportation bottleneck between Cushing and the Gulf Coast.

Canadian crude differentials also improved significantly during the second quarter as refineries returned from outages. During the quarter, light differentials were much narrower due to lower than expected synthetic crude output from oilsands producers. Heavy differentials also narrowed due to the delay of new production and debottlenecking of pipeline capacity. Differentials in North Dakota versus WTI widened again in the second quarter as the narrowing of the price difference between Cushing WTI and the Gulf Coast resulted in lower rail netbacks. As Enerplus and other producers depend on moving a portion of North Dakota production by rail to the Gulf Coast, this negatively impacted our overall netback for Fort Berthold. The amount of production that we ship by rail to the Gulf Coast will vary over time due to transportation access constraints and changes in the price differential between Cushing and the Gulf Coast.

Natural gas liquid prices weakened during the quarter due to takeaway and fractionation capacity issues in Alberta along with strong North American liquids production. As expected, we realized a significant drop in our natural gas liquids prices due to the re-contracting of volumes as of April 1, 2013. We expect prices to remain weak through 2013 and 2014 until new fractionation capacity is built within Alberta.

The average price received for our crude oil production (net of transportation costs) in the second quarter of 2013 increased by 12% to $82.95/bbl from $74.36/bbl for the same period in 2012. The improvement in our pricing is due to narrower differentials as well as a continued portfolio shift towards lighter crude oil with our production growth in North Dakota.

Natural Gas

Natural gas prices continued to rally in the second quarter with cooler end-of-winter weather causing storage levels to decrease. However, prices peaked in May and have since fallen as U.S. gas production continues to increase, in particular in the Marcellus play, coal prices remain very competitive compared to gas for power generation, and summer gas consumption for cooling demand has moderated.

In Canada, the price at AECO fell relative to Henry Hub during the quarter, as export demand dropped and Western Canadian storage began to quickly fill. We see some potential for the AECO basis differential to remain wider for the rest of summer 2013, before narrowing again later in the year.

In the U.S., we continue to see premium pricing for our liquids rich gas located in North Dakota and Montana. In the Marcellus we have contracted long term sales that are based on monthly and daily indexes. In June daily spot prices, in particular into Tennessee Gas Pipeline, fell rapidly as industry production growth continued to surprise, bringing our overall Marcellus price to US$0.18/Mcf below NYMEX for the quarter. We expect that wider differentials will continue until pipeline expansions are built to manage excess gas from producing areas. Accessing new and incremental markets will be necessary to consume the growing gas production in the Marcellus region.

For the three months ended June 30, 2013 we sold our natural gas for an average price of $3.70/Mcf (net of transportation costs) which represented a 19% increase from an average price of $3.10/mcf received during the first quarter of 2013. Our realized price increases were in-line with the strengthening of the AECO Monthly and NYMEX indices during this period. Our natural gas sales mix continues to include exposure to these indices for both our Canadian and U.S. production.

Price Risk Management

We have a price risk management program that is designed to mitigate a portion of the variability in commodity prices. The program considers our overall financial position along with the economics of our capital program and potential acquisitions. At current commodity prices our crude oil production accounts for approximately 75% of our corporate netback and therefore we believe it is prudent to have a significant level of downside price protection. We continued to add fixed price positions during and subsequent to the quarter given the rally in crude prices. As of July 22, 2013 we have swapped 22,250 bbls/day for the remainder of 2013 at an average price of US$100.35/bbl, representing approximately 75% of our forecasted net oil production after royalties. For the first half of 2014, we have swapped 19,000 bbls/day, representing approximately 64% of our forecasted net production after royalties, at an average price of US$93.39/bbl. For the second half of 2014 we have swapped 14,000 bbls/day, representing approximately 47% of our forecasted net production after royalties, at an average price of US$92.61/bbl.

As a result of the Brent – WTI differential narrowing during and subsequent to the quarter, and the potential that it could widen again, we have also added Brent – WTI fixed and ratio spread basis positions. We have entered into fixed basis spread positions for the remainder of 2013 where we pay the WTI calendar month average price and receive the Brent calendar month average price less a fixed spread of $7.09/bbl on 5,000 bbls/day. For 2014 we have entered into ratio spread basis positions where we pay the WTI calendar month average price and receive 92.9% of the Brent calendar month average price on 2,000 bbls/day.

We added minimally to our natural gas hedge position during the quarter as hedging crude provides more funds flow protection. As of July 22, 2013 we have downside protection representing approximately 32% of our forecasted natural gas production after royalties for the remainder of 2013. This protection is comprised of 51,100 Mcf/day at AECO $3.41/Mcf before premiums and 15,000 Mcf/day swapped at NYMEX US$3.85/Mcf. For 2014 we have swapped 50,000 Mcf/day at NYMEX US$4.17/Mcf and another 4,700 Mcf/day at AECO $3.96/Mcf, representing approximately 26% of our forecasted net production after royalties.

The following is a summary of our financial contracts in place at July 22, 2013 expressed as a percentage of our anticipated net production volumes after royalties:

	WTI Crude Oil[1] (US$/bbl)			AECO Natural Gas[1] (CDN$/Mcf)		NYMEX Natural Gas[1] (US$/Mcf)	
	Jul 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Jun 30, 2014	Jul 1, 2014 – Dec 31, 2014	Jul 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Dec 31, 2014	Jul 1, 2013 – Dec 31, 2013	Jan 1, 2014 – Dec 31, 2014
Purchased Puts	–	–	–	$ 3.17	–	–	–
%	–	–	–	11%	–	–	–
Sold Puts	$ 63.09	–	–	–	–	–	–
%	19%	–	–	–	–	–	–
Swaps (fixed price)	$ 100.35	$ 93.39	$ 92.61	$ 3.61	$ 3.96	$ 3.85	$ 4.17
%	75%	64%	47%	14%	2%	7%	24%
Sold Calls	$ 130.00	–	–	–	–	–	–
%	12%	–	–	–	–	–	–
Purchased Calls	$ 104.09	–	–	–	–	–	–
%	12%	–	–	–	–	–	–

(1) Based on weighted average price (before premiums), assumed average annual production of 85,000 BOE/day for 2013 and 2014, less royalties of 21%.

See Note 14 for further information on our commodity hedging.

Accounting for Price Risk Management

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. In comparison, during the second quarter of 2012 we realized cash gains of $5.0 million on our crude oil contracts. The crude oil gains realized in 2013 and 2012 were due to contracts that provided floor protection above market prices. The natural gas losses realized in the current quarter were due to market prices rising above our fixed price positions.

As the forward markets for crude oil and natural gas fluctuate and new contracts are executed and existing contracts are realized, changes in fair value are reflected as either a non-cash charge or gain to earnings. At the end of the second quarter of 2013 the fair value of our crude oil and natural gas contracts represented gain positions of $29.8 million and $7.2 million respectively. For the three and six months ended June 30, 2013 the fair value of our crude oil contracts increased $8.7 million and decreased $20.9 million respectively, while the fair value of our natural gas contracts increased $12.8 million and $3.8 million respectively.

During the second quarter of 2012 we saw significant decreases in forecast crude oil prices, which resulted in unrealized gains of $137.7 million and $120.6 million for the three and six months ended June 30, 2012 respectively.

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	Three months ended June 30, 2013		2012	
Cash gains/(losses):				
Crude Oil	$ 11.0	$ 3.17/bbl	$ 5.0	$ 1.50/bbl
Natural Gas	(1.9)	$ (0.07)/Mcf	–	$ – /Mcf
Total cash gains/(losses)	$ 9.1	$ 1.11/BOE	$ 5.0	$ 0.68/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – crude oil	$ 8.7	$ 2.51/bbl	$ 137.7	$ 41.43/bbl
Change in fair value – natural gas	12.8	$ 0.49/Mcf	–	$ – /Mcf
Total non-cash gains/(losses)	$ 21.5	$ 2.63/BOE	$ 137.7	$ 18.42/BOE
Total gains/(losses)	**$ 30.6**	**$ 3.74/BOE**	**$ 142.7**	**$ 19.10/BOE**

Risk Management Gains/(Losses) ($ millions, except per unit amounts)	Six months ended June 30, 2013		2012	
Cash gains/(losses):				
Crude Oil	$ 21.9	$ 3.16bbl	$ (5.6)	$ (0.87)/bbl
Natural Gas	(1.2)	$ (0.02)/Mcf	–	$ – /Mcf
Total cash gains/(losses)	$ 20.7	$ 1.27/BOE	$ (5.6)	$ (0.38)/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – crude oil	$ (20.9)	$ (3.02)/bbl	$ 120.6	$ 18.77/bbl
Change in fair value – natural gas	3.8	$ 0.07/Mcf	–	$ – /Mcf
Total non-cash gains/(losses)	$ (17.1)	$ (1.05)/BOE	$ 120.6	$ 8.22/BOE
Total gains/(losses)	**$ 3.6**	**$ 0.22/BOE**	**$ 115.0**	**$ 7.84/BOE**

Revenues

Crude oil and natural gas revenues were $398.6 million ($404.8 million, net of $6.2 million of transportation costs) in the second quarter of 2013, representing an increase of 27% or $84.2 million from $314.4 million ($321.2 million, net of $6.8 million of transportation costs) during the same period in 2012. Crude oil and natural gas revenues for the six months ended June 30, 2013 were $764.8 million ($778.2 million, net of $13.4 million of transportation costs), an increase of $111.5 million or 17% from $653.3 million ($666.3 million, net of $13.0 million in transportation costs) for the same period in 2012. Crude oil and natural gas revenues increased due to improvements in realized prices as well as higher production levels during the period.

Analysis of Sales Revenue(1) ($ millions)	Crude Oil	NGLs	Natural Gas	Total
Three months ended June 30, 2012	$ 247.2	$ 18.6	$ 48.6	$ 314.4
Price variance	29.8	(4.9)	40.4	65.3
Volume variance	10.4	0.8	7.7	18.9
Three months ended June 30, 2013	**$ 287.4**	**$ 14.5**	**$ 96.7**	**$ 398.6**

($ millions)	Crude Oil	NGLs	Natural Gas	Total
Six months ended June 30, 2012	$ 513.6	$ 39.2	$ 100.5	$ 653.3
Price variance	5.6	(3.9)	60.8	62.5
Volume variance	39.0	(1.8)	11.8	49.0
Six months ended June 30, 2013	**$ 558.2**	**$ 33.5**	**$ 173.1**	**$ 764.8**

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

Royalties

Royalties are paid to various government entities and other land and mineral rights owners. For the three and six months ended June 30, 2013 royalties were $81.4 million and $156.0 million respectively, compared to $62.5 million and $129.2 million for the same periods of 2012. As a percentage of oil and gas sales, net of transportation costs, royalties were 20% for the three and six months ended June 30, 2013, unchanged from 2012. We continue to expect an average royalty rate of approximately 21% in 2013.

Operating Expenses

Our operating expenses were on track at $85.4 million or $10.42/BOE during the second quarter of 2013 and $166.7 million or $10.39/BOE for the six months ended June 30, 2013. In comparison, we had operating costs of $80.5 million or $10.78/BOE and $152.6 million or $10.40/BOE for the same periods in 2012. Our operating costs have improved on a per BOE basis in 2013 mainly due to increased production from our Marcellus and Fort Berthold properties which have lower operating costs.

We are maintaining our annual guidance of $10.70/BOE for operating costs during 2013.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three and six months ended June 30, 2013 and 2012. The crude oil and natural gas classifications below contain properties according to their dominant production category. These properties may include associated crude oil, natural gas or natural gas liquids volumes which have been converted to the equivalent BOE/day or Mcfe/day and as such, the revenue per BOE or per Mcfe may not correspond with the average selling price under the "Pricing" section of this MD&A.

	Three months ended June 30, 2013		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	41,854 BOE/day	289,095 Mcfe/day	90,037 BOE/day
Netback(1) $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue(2)	$ 76.06	$ 4.14	$ 48.65
Royalties	(18.36)	(0.44)	(9.93)
Cash operating costs	(12.98)	(1.41)	(10.55)
Netback before hedging	$ 44.72	$ 2.29	$ 28.17
Cash gains/(losses)	2.88	(0.07)	1.11
Netback after hedging	$ 47.60	$ 2.22	$ 29.28
Netback before hedging ($ millions)	$ 170.3	$ 60.5	$ 230.8
Netback after hedging ($ millions)	**$ 181.3**	**$ 58.6**	**$ 239.9**

	Three months ended June 30, 2012		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average Daily Production	40,165 BOE/day	251,658 Mcfe/day	82,108 BOE/day
Netback(1) $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue(2)	$ 68.05	$ 2.87	$ 42.07
Royalties	(14.93)	(0.34)	(8.36)
Cash operating costs	(11.93)	(1.62)	(10.80)
Netback before hedging	$ 41.19	$ 0.91	$ 22.91
Cash gains/(losses)	1.38	–	0.68
Netback after hedging	$ 42.57	$ 0.91	$ 23.59
Netback before hedging ($ millions)	$ 150.6	$ 20.6	$ 171.2
Netback after hedging ($ millions)	**$ 155.6**	**$ 20.6**	**$ 176.2**

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

	Six months ended June 30, 2013		
Netbacks by Property Type	**Crude Oil**	**Natural Gas**	**Total**
Average daily production	41,936 BOE/day	280,091 Mcfe/day	88,618 E/day
Netback(1)	(per BOE)	(per Mcfe)	(per BOE)
Revenue(2)	$ 74.46	$ 3.94	$ 47.68
Royalties	(17.55)	(0.45)	(9.73)
Cash operating costs	(12.34)	(1.47)	(10.48)
Netback before hedging	$ 44.57	$ 2.02	$ 27.47
Cash gains/(losses)	2.88	(0.02)	1.29
Netback after hedging	$ 47.45	$ 2.00	$ 28.76
Netback before hedging ($ millions)	$ 338.2	$ 102.4	$ 440.6
Netback after hedging ($ millions)	**$ 360.1**	**$ 101.2**	**$ 461.3**

Netbacks by Property Type	Six months ended June 30, 2012					
		Crude Oil		Natural Gas		Total
Average daily production		38,365 BOE/day		253,702 Mcfe/day		80,649 BOE/day
Netback[1]		(per BOE)		(per Mcfe)		(per BOE)
Revenue[2]	$	73.42	$	3.05	$	44.51
Royalties		(15.91)		(0.39)		(8.80)
Cash operating costs		(11.70)		(1.51)		(10.32)
Netback before hedging	$	45.81	$	1.15	$	25.39
Cash gains/(losses)		(0.80)		–		(0.38)
Netback after hedging	$	45.01	$	1.15	$	25.01
Netback before hedging ($ millions)	$	319.9	$	52.9	$	372.8
Netback after hedging ($ millions)	**$**	**314.3**	**$**	**52.9**	**$**	**367.2**

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

Our crude oil properties accounted for 77% of our corporate netback before hedging for the first six months of 2013 compared to 86% for the same period in 2012. Crude oil netbacks after hedging per BOE have increased for the three and six months ended June 30, 2013 primarily due to higher realized crude oil prices and cash hedging gains. Natural gas netbacks per Mcfe after hedging increased mainly due to higher realized natural gas prices.

General and Administrative Expenses ("G&A")

G&A expenses decreased during the second quarter of 2013 to $18.8 million or $2.29/BOE compared to $20.7 million or $2.76/BOE in the second quarter of 2012, mainly due to lower legal and professional fees. For the six months ended June 30, 2013 G&A expenses increased to $43.5 million or $2.71/BOE compared to $41.4 million or $2.82/BOE for the same period in 2012, primarily due to one-time charges recorded in the first quarter of 2013.

Cash G&A Expenses	Three months ended June 30,				Six months ended June 30,			
		2013		2012		2013		2012
G&A expenses ($ millions)	$	18.8	$	20.7	$	43.5	$	41.4
G&A expenses (per BOE)	$	2.29	$	2.76	$	2.71	$	2.82

We continue to expect cash G&A expenses to be approximately $2.70/BOE during 2013.

Equity Based Compensation Expenses

Equity based compensation expenses totaled $5.9 million for the second quarter of 2013 and $12.4 million for the first six months of 2013, compared to $0.3 million and $4.9 million during the same periods during 2012. These expenses include charges related to our long-term incentive plans ("LTI plans") and our stock option plan (see Note 13 for further details). The costs of our LTI plans are dependent on our share price and can fluctuate from period to period. The increased costs in 2013 were the result of the increase in our share price.

We also recorded non-cash gains on our LTI equity swaps of $0.8 million for the second quarter and $2.3 million for the first six months of 2013, compared to $0.3 million of non-cash gains during the same periods in 2012. Utilizing the swaps, we have effectively fixed the future settlement cost on our LTI plans at a weighted average price of $13.21 per share on 1,130,000 shares, representing approximately 70% of the notional shares outstanding under these plans.

	Three months ended June 30,		Six months ended June 30,	
Equity Based Compensation Expenses ($ millions)	2013	2012	2013	2012
Cash:				
LTI plans expense/(recovery)	$ 3.7	$ (1.5)	$ 9.2	$ 0.1
Non-Cash:				
LTI plans – equity swap gain	(0.8)	(0.3)	(2.3)	(0.3)
Stock option plan	3.0	2.1	5.5	5.1
Total equity based compensation expenses	**$ 5.9**	**$ 0.3**	**$ 12.4**	**$ 4.9**

	Three months ended June 30,		Six months ended June 30,	
Equity Based Compensation Expenses (Per BOE)	2013	2012	2013	2012
Cash:				
LTI plans expense/(recovery)	$ 0.45	$ (0.19)	$ 0.57	$ 0.01
Non-Cash:				
LTI plans – equity swap gain	(0.09)	(0.04)	(0.14)	(0.02)
Stock option plan	0.36	0.28	0.34	0.34
Total equity based compensation expenses	**$ 0.72**	**$ 0.05**	**$ 0.77**	**$ 0.33**

Based on our current share price performance, we have increased our forecast for cash equity based compensation for 2013 from $0.45/BOE to $0.60/BOE.

Finance Expense

Interest on our senior notes and bank credit facility for the three and six months ended June 30, 2013 totaled $14.3 million and $28.5 million respectively, compared to $13.4 million and $24.3 million for the same periods in 2012. The increase is due to higher average debt levels in 2013 along with an increased weighting of senior notes with higher interest rates.

Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of debt transaction costs and unrealized gains and losses resulting from the change in fair value of our interest rate swaps and the interest component on our cross currency interest rate swap ("CCIRS"). See Note 10 for further details.

	Three months ended June 30,		Six months ended June 30,	
Finance Expense ($ millions)	2013	2012	2013	2012
Interest on senior notes and bank facility	$ 14.3	$ 13.4	$ 28.5	$ 24.3
Non-cash finance expense	4.2	4.0	8.4	8.9
Total finance expense	**$ 18.5**	**$ 17.4**	**$ 36.9**	**$ 33.2**

At June 30, 2013 approximately 68% of our debt was based on fixed interest rates.

Foreign Exchange

We recorded a net foreign exchange loss of $2.2 million during the second quarter of 2013. In comparison, realized foreign exchange losses of $11.2 million were offset by unrealized foreign exchange gains of $11.2 million during the second quarter of 2012.

During the second quarter of 2013 the Canadian dollar continued to weaken against the U.S. dollar. On June 19, 2013 we made the fourth US$35.0 million principal repayment on our US$175.0 million senior notes. In connection with this payment we also settled the underlying CCIRS, which resulted in an $18.0 million realized foreign exchange loss. This realized loss was partially offset by realized foreign exchange gains on the settlement of short-term U.S. dollar bank debt that matured during the period.

We recorded net unrealized foreign exchange gains during the second quarter of $12.7 million, mainly due to mark-to-market gains on our CCIRS and foreign exchange swaps. These gains were partially offset by unrealized losses on the period end translation of our U.S. dollar debt and working capital. See Note 11 for further details.

	Three months ended June 30,		Six months ended June 30,	
Foreign Exchange ($ millions)	2013	2012	2013	2012
Realized loss/(gain)	$ 14.9	$ 11.2	$ 17.6	$ 5.9
Unrealized loss/(gain)	(12.7)	(11.2)	(11.1)	(11.2)
Total Foreign Exchange loss/(gain)	**$ 2.2**	**$ –**	**$ 6.5**	**$ (5.3)**

Capital Investment

Capital spending for the second quarter totaled $139.7 million compared to $208.6 million during the same period in 2012 and $172.9 million during the first quarter of 2013. Spending levels in the quarter slowed due to the timing of development plans, spring break-up and wet weather in June. Despite the slow-down our annual capital program is on track and we continue to expect annual spending of approximately $685 million. Second quarter spending was primarily focused on our crude oil properties with $77.9 million directed towards our Fort Berthold crude oil property and $34.5 million spent on our Canadian oil properties. Spending on our natural gas assets included $17.1 million in the Marcellus and $6.0 million on our deep basin properties in Canada.

Property and land acquisitions for the second quarter totaled $51.7 million, which included the acquisition of an incremental 50% working interest in our Pouce Coupe light oil waterflood property for $34.0 million after adjustments. Land acquisitions totaled $16.7 million and were primarily focused on additional acreage positions around our existing North Dakota and Marcellus interests. During the second quarter of 2012 we spent $23.6 million, which included $8.2 million on undeveloped land and $15.4 million on our Marcellus carry obligation.

Dispositions

During the second quarter we recognized aggregate proceeds of $71.3 million through our disposition activity. The largest transactions were the sale of our Canadian non-core oil assets in Taylorton and Turner Valley that had production of approximately 600 BOE/day for proceeds of $57.2 million. We also disposed of non-core oil assets at Willesden Green for $6.7 million, along with U.S. undeveloped land for $7.4 million. In aggregate, we recognized losses of $4.5 million during the quarter on these transactions.

Our total capital investment activity for the three and six months ended June 30, 2013 are outlined below:

	Three months ended June 30,		Six months ended June 30,	
Capital Investment ($ millions)	2013	2012	2013	2012
Capital spending	$ 139.7	$ 208.6	$ 312.6	$ 525.7
Office capital	0.8	3.6	2.2	6.1
Sub-total	140.5	212.2	314.8	531.8
Property and land acquisitions	51.7	23.6	55.7	56.6
Property dispositions	(71.3)	0.1	(72.6)	(52.5)
Sub-total	(19.6)	23.7	(16.9)	4.1
Total net capital investment	**$ 120.9**	**$ 235.9**	**$ 297.9**	**$ 535.9**

Subsequent to the second quarter, we entered into agreements to divest of non-core Canadian properties with production of approximately 1,000 BOE/day for proceeds of approximately $85.4 million, before closing adjustments. We also closed the sale of certain facilities in our Western U.S. operations for proceeds of $34.3 million and entered into a new fee based arrangement with respect to these assets. These assets have been classified as assets held for sale on our balance sheet at June 30, 2013. See Note 15 for further information.

Including the transactions subsequent to the second quarter, we have sold, or have entered into agreements to sell, non-core assets for aggregate proceeds of $192.3 million and related production of approximately 1,700 BOE/day. We have also invested approximately $55.7 million in property and land acquisitions with related production of approximately 400 BOE/day.

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

DD&A of property, plant and equipment ("PP&E") is recognized using the unit-of-production method based on proved plus probable reserves. For the three and six months ended June 30, 2013 DD&A increased to $132.5 million and $259.4 million respectively, compared to $128.2 million and $246.7 million during the same periods in 2012, primarily due to higher production.

Other Assets

Other assets consist of our portfolio of equity investments in other oil and gas companies. These investments are carried at their estimated fair value with changes in fair value recorded in other comprehensive income. The change in fair value of these investments for the three and six months ended June 30, 2013 resulted in unrealized gains of $2.3 million and $3.9 million respectively, compared to unrealized losses of $46.9 million and $51.1 million for the same periods last year. The unrealized losses in 2012 primarily related to our investment in Laricina Energy Ltd. which we disposed of in the third quarter of 2012.

Decommissioning Liabilities

In connection with our operations, we incur abandonment and reclamation costs related to assets such as surface leases, wells, facilities and pipelines. Total decommissioning liabilities included on our balance sheet are estimated by management based on our net ownership interest, estimated costs to abandon and reclaim and the estimated timing of the costs to be incurred in future periods. We have estimated the net present value of our decommissioning liability to be $552.0 million at June 30, 2013 compared to $599.7 million at December 31, 2012. For the six months ended June 30, 2013 there was a $47.7 million decrease in decommissioning liability resulting primarily from the change in the risk-free rate used to calculate the present value of the liability, which increased to 2.89% from 2.36% at December 31, 2012. See Notes 9 and 15 for further information.

Taxes

Current Income Taxes

We recorded a current tax expense of $1.4 million for the three months ended June 30, 2013 compared to $3.8 million for the same period in 2012. 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.

We continue to expect to pay U.S. cash taxes of approximately 3% of U.S. cash flow until 2016. We currently do not expect to pay material cash taxes in Canada until after 2016. These estimates may vary depending on numerous factors including commodity prices, capital spending, tax regulations and acquisition and disposition activity.

Deferred Income Taxes

We recorded a deferred tax expense of $25.9 million for the three months ended June 30, 2013 compared to an expense of $43.1 million for the same period in 2012. The decrease in deferred income tax expense is due to lower net income during the period.

Net Income

Net income for the second quarter of 2013 was $52.6 million or $0.26 per share compared to $100.3 million or $0.51 per share for the second quarter of 2012. Net income for the six months ended June 30, 2013 totaled $47.4 million or $0.24 per share compared to $66.4 million or $0.34 per share for the same period in 2012.

Increased production and improvements in realized pricing in 2013 generated higher oil and gas sales however this was offset by lower mark-to-market gains on our commodity derivative instruments and a decrease in gains on asset dispositions.

SELECTED CANADIAN AND U.S. FINANCIAL RESULTS

The following tables provide a geographical analysis of key operating and financial results for the three and six months ended June 30, 2013 and 2012.

	Three months ended June 30, 2013			Three months ended June 30, 2012		
(CDN$ millions, except per unit amounts)	Canada	U.S.	Total	Canada	U.S.	Total
Average Daily Production Volumes						
Crude oil (bbls/day)	18,364	19,702	38,066	21,028	15,499	36,527
Natural gas liquids (bbls/day)	2,975	522	3,497	2,947	446	3,393
Natural gas (Mcf/day)	186,569	104,272	290,841	203,030	50,096	253,126
Total average daily production (BOE/day)	52,434	37,603	90,037	57,813	24,295	82,108
Pricing[(1)]						
Crude oil (per bbl)	$ 79.06	$ 86.58	$ 82.95	$ 69.50	$ 80.96	$ 74.36
Natural gas liquids (per bbl)	49.05	26.21	45.64	63.79	35.80	60.11
Natural gas (per Mcf)	3.39	4.26	3.70	1.91	2.70	2.06
Capital Expenditures						
Capital spending	$ 44.4	$ 95.3	$ 139.7	$ 45.6	$ 163.0	$ 208.6
Acquisitions	35.0	16.7	51.7	2.4	21.2	23.6
Dispositions	(63.9)	(7.4)	(71.3)	–	0.1	0.1
Revenues						
Oil and gas sales[(1)]	$ 203.6	$ 195.0	$ 398.6	$ 185.0	$ 129.4	$ 314.4
Royalties[(2)]	(30.5)	(50.9)	(81.4)	(28.7)	(33.8)	(62.5)
Commodity derivative instruments gain	30.6	–	30.6	142.7	–	142.7
Expenses						
Operating	$ 63.8	$ 21.6	$ 85.4	$ 68.3	$ 12.2	$ 80.5
General and administrative	15.7	3.1	18.8	16.9	3.8	20.7
Equity based compensation	5.6	0.3	5.9	0.6	(0.3)	0.3
Depletion, depreciation and amortization	62.3	70.2	132.5	79.8	48.4	128.2
Current income tax expense	0.1	1.3	1.4	0.5	3.3	3.8

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) U.S. royalties include state production tax.

(CDN$ millions, except per unit amounts)	Six months ended June 30, 2013 Canada	Six months ended June 30, 2013 U.S.	Six months ended June 30, 2013 Total	Six months ended June 30, 2012 Canada	Six months ended June 30, 2012 U.S.	Six months ended June 30, 2012 Total
Average Daily Production Volumes						
Crude oil (bbls/day)	18,764	19,429	38,193	20,814	14,486	35,300
Natural gas liquids (bbls/day)	3,045	501	3,546	3,372	326	3,698
Natural gas (Mcf/day)	182,214	99,061	281,275	205,571	44,334	249,905
Total average daily production (BOE/day)	52,178	36,440	88,618	58,449	22,200	80,649
Pricing(1)						
Crude oil (per bbl)	$ 73.44	$ 87.80	$ 80.74	$ 77.20	$ 83.86	$ 79.93
Natural gas liquids (per bbl)	55.81	30.02	52.16	60.05	40.25	58.30
Natural gas (per Mcf)	3.15	3.90	3.41	2.01	2.89	2.17
Capital Expenditures						
Capital spending	$ 127.4	$ 185.2	$ 312.6	$ 156.8	$ 368.9	$ 525.7
Property and land acquisitions	37.6	18.1	55.7	13.9	42.8	56.7
Property dispositions	(65.2)	(7.4)	(72.6)	(30.7)	(21.8)	(52.5)
Revenues						
Oil and gas sales(1)	$ 385.3	$ 379.5	$ 764.8	$ 405.0	$ 248.4	$ 653.4
Royalties(2)	(56.8)	(99.2)	(156.0)	(64.4)	(64.8)	(129.2)
Commodity derivative instruments gain/(loss)	3.6	–	3.6	115.0	–	115.0
Expenses						
Operating	$ 129.9	$ 36.8	$ 166.7	$ 128.4	$ 24.2	$ 152.6
General and administrative	37.1	6.4	43.5	34.0	7.4	41.4
Equity based compensation	11.6	0.8	12.4	5.2	(0.3)	4.9
Depletion, depreciation and amortization	126.6	132.8	259.4	160.5	86.2	246.7
Current income tax expense/(recovery)	0.1	2.6	2.7	(0.1)	4.6	4.5

(1) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(2) U.S. royalties include state production tax.

QUARTERLY FINANCIAL INFORMATION

Higher realized commodity prices combined with increased production volumes contributed to higher revenues in the second quarter of 2013. During 2012 oil and gas sales were relatively flat as increasing production volumes were offset by lower realized commodity prices. During 2011 we saw higher crude oil prices and declining natural gas prices combined with lower production levels, which resulted in fluctuating oil and gas sales throughout the year.

Quarterly Financial Information (CDN$ millions, except per share amounts)	Oil and Gas Sales(1)	Net Income/(Loss)	Net Income/(Loss) Per Share Basic	Net Income/(Loss) Per Share Diluted
2013				
Second Quarter	$ 398.6	$ 52.6	$ 0.26	$ 0.26
First Quarter	366.2	(5.2)	(0.03)	(0.03)
Total	**$ 764.8**	**$ 47.4**	**$ 0.24**	**$ 0.24**
2012				
Fourth Quarter	$ 360.7	$ (158.7)	$ (0.80)	$ (0.80)
Third Quarter	324.9	(63.5)	(0.32)	(0.32)
Second Quarter	314.4	100.3	0.51	0.51
First Quarter	339.0	(33.8)	(0.18)	(0.18)
Total	**$ 1,339.0**	**$ (155.7)**	**$ (0.80)**	**$ (0.80)**
2011				
Fourth Quarter	$ 357.3	$ (299.4)	$ (1.66)	$ (1.65)
Third Quarter	312.9	111.3	0.62	0.62
Second Quarter	354.2	268.0	1.50	1.49
First Quarter	318.7	29.5	0.17	0.16
Total	**$ 1,343.1**	**$ 109.4**	**$ 0.61**	**$ 0.61**

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

LIQUIDITY AND CAPITAL RESOURCES

We have continued to strengthen our balance sheet and liquidity in 2013. We have seen a significant increase in our funds flow and our disposition activities have generated proceeds of $192.3 million, including transactions closing subsequent to the quarter. As a result, we have eliminated our year-to-date funding shortfall. At June 30, 2013 we have a conservative trailing 12 month debt to cash flow ratio of 1.6x and approximately $670.0 million of undrawn credit capacity.

Our adjusted payout ratio has also shown significant improvement in 2013. Our adjusted payout ratio, which is calculated as dividends (net of our stock dividends and DRIP proceeds) plus capital spending and office capital divided by funds flow, was 89% for the second quarter of 2013 and 106% for the first six months of 2013, compared to 197% and 227% for the same periods in 2012. The decrease in our adjusted payout ratio was a result of lower capital spending, higher funds flow along with the reduction in our monthly dividend from $0.18 to $0.09 at the end of the second quarter of 2012.

Total debt at June 30, 2013, including the current portion, was $1,143.8 million compared to $1,069.6 million at December 31, 2012. Total debt at June 30, 2013 was comprised of $330.2 million of bank indebtedness and $813.6 million of senior notes.

Our working capital deficiency at June 30, 2013, excluding current deferred financial assets and credits and held for sale assets and liabilities, was $168.6 million compared to $167.2 million at December 31, 2012. 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, 2013**	**December 31, 2012**
Long-term debt to funds flow (12 month trailing)(1)	1.6 x	1.7 x
Funds flow to interest expense (12 month trailing)(2)	16.5 x	12.1 x
Long-term debt to long-term debt plus equity(1)	27%	26%

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

At June 30, 2013 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

During the three and six months ended June 30, 2013 we reported dividends of $54.0 million ($0.27/share) and $107.8 million ($0.54/share) respectively, of which $11.4 million and $21.5 million respectively, was non-cash and related to our Stock Dividend Program ("SDP"). We 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 at this time.

Our SDP allows shareholders to elect to receive their dividends in the form of shares instead of cash. Currently approximately 21% of our shareholders participate in the SDP, representing $3.8 million of dividends per month. As with our previous DRIP, the SDP will serve as a source of capital by allowing us to retain cash that would otherwise be paid out as dividends.

Shareholders' Capital

During the second quarter of 2013, a total of 805,000 shares were issued for $11.4 million pursuant to the SDP and stock option plan. A total of 869,000 shares were issued for $12.5 million under our former DRIP and the stock option plan for the same period in 2012. For the six months ended June 30, 2013, a total of 1,584,000 shares were issued for $21.5 million pursuant to the SDP and stock option plan, compared to 1,464,000 shares issued for $25.8 million during the same period in 2012 under the SDP, former DRIP and the stock option plan. See Note 13 for further information.

We had 200,268,000 shares outstanding at June 30, 2013 compared to 197,332,000 shares outstanding at June 30, 2012 and 198,684,000 shares outstanding at December 31, 2012. The weighted average basic number of shares outstanding for the six months ended June 30, 2013 was 199,430,000 (2012 – 193,306,000). At August 8, 2013 we had 201,109,000 shares outstanding.

Change in U.S. Filing Status

Pursuant to U.S. securities regulations we expect that we will no longer qualify as a "foreign private issuer" as of January 1, 2014 as over 50% of our common shares are held by U.S. residents and over 50% of our assets are located in the U.S. As a result, we believe that we will be considered a U.S. domestic issuer and will become subject to U.S. domestic reporting requirements for all U.S. filings completed on or after January 1, 2014, which will include our annual 2013 filings.

This change in filing status is not expected to impact our operations, but rather it will change the way in which we report and file our results.

Some of the consequences of no longer qualifying as a "foreign private issuer" are summarized below.

Financial Statements

Our financial statements will be presented in accordance with United States Generally Accepted Accounting Principles ("US GAAP") instead of IFRS beginning with our year ended December 31, 2013, including the comparative periods for 2012 and 2011. The US GAAP financial statements will satisfy our Canadian filing obligations and IFRS statements will no longer be prepared.

The most significant differences between US GAAP and IFRS that are expected to impact us relate to the accounting for our oil and gas assets and particularly impairment calculations and the accounting treatment for dispositions. As we are recasting our comparative periods in accordance with US GAAP, any previously recorded IFRS asset impairments/reversals or gains/losses on asset dispositions will be reversed and recast in accordance with US GAAP. Other differences include different discount rates used for decommissioning liabilities associated with our assets along with differences in balance sheet presentation for our assets. We expect these changes will impact our earnings however we do not expect a material change in our key performance indicators such as funds flow, debt levels, capital spending, operating costs, G&A expenses, netbacks or adjusted payout ratios.

Equity Offerings

Historically as a foreign private issuer we completed Canadian "bought deal" style public offerings and separate U.S. prospectuses were not required. As a U.S. domestic issuer we will generally need to file U.S. prospectuses for any private or public equity offerings completed after January 1, 2014. In addition, we would continue to be subject to the applicable Canadian prospectus requirements. These additional filing obligations could impact the cost and execution of our equity offerings.

Production and Reserves Information

In accordance with U.S. protocol our sales revenue and volumes would be presented on a net (after royalty) basis. We would also provide supplementary disclosures for gross sales revenue and volumes to facilitate comparisons with Canadian peers.

Our reserves information would be prepared and filed under both U.S. and Canadian standards. Under U.S. reserve standards proved reserves are generally presented, historic 12 month average price is held constant and reserves are reported on a net (after royalty) basis.

2013 GUIDANCE

A summary of our 2013 guidance is below.

Summary of 2013 Expectations	Target
Average annual production	85,000 BOE/day (higher end of range of previous guidance)
Exit rate production	84,000 – 88,000 BOE/day
Capital spending	$685 million
Production mix (volumes)	48% crude oil and liquids (decrease from 50% crude oil and liquids)
Average royalty rate (% of gross sales, net of transportation)	21%
Operating costs	$10.70/BOE
G&A expenses – cash	$2.70/BOE
Equity based compensation expenses – cash	$0.60/BOE (increase from $0.45/BOE)
Cash taxes (% of U.S. funds flow)	~3%
Average interest and financing costs	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, 2013, 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, 2013 and ending June 30, 2013 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 2013 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 our commodity risk management programs; future royalty rates on our production; anticipated cash and non-cash G&A, equity based compensation and financing expenses; operating costs; capital spending levels in 2013 and its impact on our production level and land holdings; our ability to reallocate funds within our 2013 capital program; potential future asset impairments and reversals; the amount of our future abandonment and reclamation costs and decommissioning liabilities; 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; 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 and equity issuances and expected use of proceeds therefrom; and the amount and timing, and use of proceeds from, future asset dispositions; the expected change of our status from "foreign private issuer" to U.S. domestic issuer as of January 1, 2014 and expected changes in our reporting related thereto; and our ability to improve our trading multiple and create significant value for our shareholders.*

The forward-looking information contained in this MD&A reflects several material factors, expectations and assumptions including, without limitation: that we will conduct our operations and achieve results of operations as anticipated; that our development plans will achieve the expected results; 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 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 the Annual MD&A and in our other public filings).

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

Statements

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	June 30, 2013	December 31, 2012
Assets			
Current assets			
Cash		$ 10,756	$ 5,200
Accounts receivable	15	168,984	150,372
Deferred financial assets	14	48,047	54,165
Other current		15,260	15,068
Assets held for sale	15	93,918	–
		$ 336,965	$ 224,805
Exploration and evaluation assets	4	$ 797,826	$ 773,820
Property, plant and equipment	5,15	4,257,079	4,242,447
Goodwill		159,799	151,390
Deferred financial assets	14	16,532	8,013
Other assets	7	14,260	11,687
Total Assets		$ 5,582,461	$ 5,412,162
Liabilities			
Current liabilities			
Accounts payable		$ 297,441	$ 274,387
Dividends payable		18,032	17,882
Current portion of long-term debt	8	48,145	45,566
Deferred financial credits	14	24,161	18,522
Liabilities associated with assets held for sale	15	6,562	–
		$ 394,341	$ 356,357
Long-term debt	8	$ 1,095,659	$ 1,023,999
Deferred financial credits	14	–	17,127
Deferred tax liability		416,660	365,473
Decommissioning liability	9,15	545,395	599,652
		$ 2,057,714	$ 2,006,251
Total Liabilities		$ 2,452,055	$ 2,362,608
Equity			
Shareholders' capital	13	$ 3,839,570	$ 3,818,043
Contributed surplus	13	41,563	36,088
Accumulated deficit		(797,171)	(736,761)
Accumulated other comprehensive income/(loss)		46,444	(67,816)
		$ 3,130,406	$ 3,049,554
Total Liabilities & Equity		$ 5,582,461	$ 5,412,162

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income and Comprehensive Income

(CDN$ thousands) unaudited	Note	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Revenues					
Oil and gas sales		$ 404,827	$ 321,163	$ 778,252	$ 666,314
Royalties		(81,364)	(62,453)	(156,032)	(129,179)
Commodity derivative instruments gain	14	30,622	142,710	3,567	115,056
		$ 354,085	$ 401,420	$ 625,787	$ 652,191
Expenses					
Operating		$ 85,369	$ 80,520	$ 166,717	$ 152,583
General and administrative		18,804	20,653	43,483	41,373
Equity based compensation	13	5,862	322	12,392	4,897
Transportation		6,232	6,808	13,429	12,960
Depletion, depreciation and amortization	5	132,537	128,217	259,415	246,735
Impairments	6	–	–	–	86,906
Foreign exchange loss/(gain)	11	2,184	44	6,536	(5,276)
Finance expense	10	18,536	17,408	36,912	33,206
Asset disposition loss/(gain)		4,483	–	4,266	(24,100)
Other expense/(income)		156	228	498	(114)
		$ 274,163	$ 254,200	$ 543,648	$ 549,170
Income before taxes		$ 79,922	$ 147,220	$ 82,139	$ 103,021
Current tax expense	12	1,401	3,845	2,708	4,548
Deferred tax expense	12	25,899	43,111	32,047	32,030
Net Income		$ 52,622	$ 100,264	$ 47,384	$ 66,443
Other Comprehensive Income					
Change due to marketable securities (net of tax)	7				
Unrealized gains/(losses)		$ 2,345	$ (46,901)	$ 3,892	$ (51,077)
Realized losses reclassified to net income		–	–	(190)	–
Change in cumulative translation adjustment		70,374	30,731	110,558	1,747
Other Comprehensive Income/(loss), net of tax		$ 72,719	$ (16,170)	$ 114,260	$ (49,330)
Total Comprehensive Income		$ 125,341	$ 84,094	$ 161,644	$ 17,113
Net income per share					
Basic		$ 0.26	$ 0.51	$ 0.24	$ 0.34
Diluted		$ 0.26	$ 0.51	$ 0.24	$ 0.34
Weighted average number of shares outstanding (thousands)	13				
Basic		199,825	196,768	199,430	193,306
Diluted		200,119	196,768	199,586	193,393

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	**2013**	**2012**
Shareholders' Capital		
Balance, beginning of year	$ 3,818,043	$ 3,442,364
Public offering	–	330,618
Stock Option Plan – cash	29	1,180
Stock Option Plan – non cash	3	1,119
Dividend Reinvestment Plan	–	19,150
Stock Dividend Program	21,495	5,443
Balance, end of period	$ 3,839,570	$ 3,799,874
Contributed Surplus		
Balance, beginning of year	$ 36,088	$ 26,910
Stock Option Plan – exercised	(3)	(1,119)
Stock Option Plan – expensed	5,478	5,109
Balance, end of period	$ 41,563	$ 30,900
Accumulated Deficit		
Balance, beginning of year	$ (736,761)	$ (279,467)
Net income	47,384	66,443
Dividends to shareholders	(107,794)	(194,594)
Balance, end of period	$ (797,171)	$ (407,618)
Accumulated other comprehensive income		
Balance, beginning of year	$ (67,816)	$ 87,172
Changes due to marketable securities (net of tax)		
Unrealized gains/(losses)	3,892	(4,176)
Realized gains reclassified to net income	(190)	–
Change in cumulative translation adjustment	110,558	1,747
Balance, end of period	$ 46,444	$ 37,842
Total Equity	$ 3,130,406	$ 3,460,998

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

	Three months ended June 30,		Six months ended June 30,	
(CDN$ thousands) unaudited	2013	2012	2013	2012
Operating Activities				
Net income	$ 52,622	$ 100,264	$ 47,384	$ 66,443
Non-cash items add/(deduct):				
Depletion, depreciation and amortization	132,537	128,217	259,415	246,735
Impairments	–	–	–	86,906
Change in fair value of derivative instruments	(47,943)	(161,210)	(13,889)	(139,386)
Deferred tax expense	25,899	43,111	32,047	32,030
Foreign exchange loss on U.S. dollar debt and working capital	12,218	11,920	16,538	9,555
Accretion expense	3,313	3,515	6,822	6,968
Equity based compensation – Stock Option Plan	2,951	2,117	5,478	5,109
Amortization of debt transaction costs	615	414	1,230	794
Derivative settlement on senior note principal repayment	18,011	18,043	18,011	18,043
Asset disposition loss/(gain)	4,483	156	4,266	(23,944)
Funds flow	$ 204,706	$ 146,547	$ 377,302	$ 309,253
Decommissioning expenditures	(2,957)	(3,712)	(6,335)	(11,010)
Changes in non-cash operating working capital	(6,325)	14,421	(14,312)	(72,006)
Cash flow from operating activities	$ 195,424	$ 157,256	$ 356,655	$ 226,237
Financing Activities				
Issuance of shares	$ 8	$ 7,050	$ 29	$ 350,948
Cash dividends	(42,620)	(83,156)	(86,299)	(189,151)
Change in bank debt	14,670	(126,742)	70,089	(126,971)
Repayment of senior notes	(35,655)	(35,623)	(35,655)	(35,623)
Proceeds from senior note issue	–	406,088	–	406,088
Derivative settlement on senior note principal repayment	(18,011)	(18,043)	(18,011)	(18,043)
Changes in non-cash financing working capital	81	(17,604)	151	(14,849)
Cash flow from financing activities	$ (81,527)	$ 131,970	$ (69,696)	$ 372,399
Investing Activities				
Capital expenditures	$ (140,465)	$ (212,173)	$ (314,838)	$ (531,743)
Property and land acquisitions	(51,692)	(23,649)	(55,659)	(56,669)
Property dispositions	71,293	(87)	72,624	22,524
Sale of equity investments	–	4,410	1,883	4,410
Changes in non-cash investing working capital	10,012	(48,972)	20,735	(34,260)
Cash flow from investing activities	$ (110,852)	$ (280,471)	$ (275,255)	$ (595,738)
Effect of exchange rate changes on cash	$ (4,842)	$ (3,033)	$ (6,148)	$ (1,352)
Change in cash	$ (1,797)	$ 5,722	$ 5,556	$ 1,546
Cash, beginning of period	12,553	1,453	5,200	5,629
Cash, end of period	$ 10,756	$ 7,175	$ 10,756	$ 7,175
Supplementary Cash Flow Information				
Cash income taxes paid/(received)	$ 356	$ 3,213	$ (4,890)	$ 17,651
Cash interest paid	$ 26,347	$ 17,058	$ 29,221	$ 21,525

See accompanying notes to the Condensed Consolidated Financial Statements

Notes

Notes to Condensed Consolidated Financial Statements

(unaudited)

1. REPORTING ENTITY

These interim condensed consolidated financial statements ("interim Consolidated Financial Statements") and notes present the results of Enerplus Corporation 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 8, 2013.

2. BASIS OF PREPARATION

Enerplus' interim Consolidated Financial Statements present its results of operations and financial position under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") for the three and six months ended June 30, 2013 and the 2012 comparative periods. They have been prepared in accordance with IAS 34, "Interim Financial Reporting". These interim Consolidated Financial Statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with Enerplus' audited Consolidated Financial Statements as of December 31, 2012. There have been no changes to the use of estimates or judgments since December 31, 2012.

3. SIGNIFICANT ACCOUNTING POLICIES

On January 1, 2013, Enerplus adopted the following new accounting standards that were issued by the IASB. The adoption of these standards did not have a material impact on Enerplus' interim Consolidated Financial Statements.

- IFRS 7 *Financial Instruments Disclosures*
- IFRS 10 *Consolidated Financial Statements*
- IFRS 11 *Joint Arrangements*.
- IFRS 12 *Disclosure of Interests in Other Entities*
- IFRS 13 *Fair Value Measurement*
- IAS 27 *Consolidation and Separate Financial Statements*
- IAS 28 *Investments in Joint Ventures*

4. EXPLORATION AND EVALUATION ("E&E ASSETS")

Carrying value ($ thousands)	**E&E assets**
As at December 31, 2012	$ 773,820
Capital spending and acquisitions	55,986
Dispositions	(9,728)
Transfers to Property, Plant and Equipment	(48,146)
Foreign currency translation adjustment	25,894
As at June 30, 2013	**$ 797,826**

As at June 30, 2013 the E&E asset balance of $797,826,000 (December 31, 2012 – $773,820,000) consists of undeveloped lands and assets that management has not fully evaluated for technical feasibility and commercial viability.

5. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

Carrying value before accumulated depletion and depreciation ($ thousands)	Developed and Producing ("D&P assets")	Office and other	Total
As at December 31, 2012	$ 6,684,154	$ 82,588	$ 6,766,742
Capital spending and acquisitions	312,261	2,251	314,512
Transfers from E&E assets	48,146	–	48,146
Change in decommissioning costs (Note 9)	(48,101)	–	(48,101)
Dispositions	(97,608)	–	(97,608)
Foreign currency translation adjustment	145,145	622	145,767
As at June 30, 2013	**$ 7,043,997**	**$ 85,461**	**$ 7,129,458**

Accumulated Depletion and Depreciation	D&P assets	Office and other	Total
As at December 31, 2012	$ 2,463,903	$ 60,392	$ 2,524,295
Depletion and Depreciation	256,186	3,229	259,415
Dispositions	(28,455)	–	(28,455)
Foreign currency translation adjustment	24,245	202	24,447
As at June 30, 2013	**$ 2,715,879**	**$ 63,823**	**$ 2,779,702**

Net carrying value	D&P assets	Office and other	Total
As at December 31, 2012	$ 4,220,251	$ 22,196	$ 4,242,447
As at June 30, 2013	**$ 4,328,118**	**$ 21,638**	**$ 4,349,756**

At June 30, 2013 $92,677,000 of the net carrying value above has been classified as assets held for sale on the Consolidated Balance Sheet. Refer to Note 15 for further information.

6. IMPAIRMENT

During the three and six months ended June 30, 2013 Enerplus did not record any impairments. For the same periods in 2012, impairment losses were $nil and $86,906,000 respectively.

7. OTHER ASSETS

Other assets of $14,260,000 (December 31, 2012 – $11,687,000) represent Enerplus' marketable securities portfolio. For the three and six months ended June 30, 2013 the change in fair value of these investments represented unrealized gains of $2,345,000 ($2,685,000 before tax) and $3,892,000 ($4,456,000 before tax) respectively. For the same periods in 2012, the change in fair value of these investments represented unrealized losses of $46,901,000 ($53,917,000 before tax) and $51,077,000 ($58,709,000 before tax) respectively.

8. DEBT

($ thousands)	June 30, 2013	December 31, 2012
Current:		
Senior notes	$ 48,145	$ 45,566
	$ 48,145	$ 45,566
Long term:		
Bank credit facility	$ 330,185	$ 260,950
Senior notes	765,474	763,049
	$ 1,095,659	$ 1,023,999
Total debt	**$ 1,143,804**	**$ 1,069,565**

Senior Notes

The terms and rates of the Company's senior notes at June 30, 2013 are detailed below:

Issue Date	Interest Payment Dates	Principal Repayment	Coupon Rate	Original Principal ($ thousands)	Remaining Principal ($ thousands)	CDN$ Carrying Value ($ thousands)
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2019	4.34%	CDN$30,000	CDN$30,000	$ 30,000
May 15, 2012	May 15 and Nov 15	Bullet payment on May 15, 2022	4.40%	US$20,000	US$20,000	21,024
May 15, 2012	May 15 and Nov 15	5 equal annual installments beginning May 15, 2020	4.40%	US$355,000	US$355,000	373,176
June 18, 2009	June 18 and Dec 18	Bullet payment on June 18, 2015	6.37%	CDN$40,000	CDN$40,000	40,000
June 18, 2009	June 18 and Dec 18	Bullet payment on June 18, 2015	6.82%	US$40,000	US$40,000	42,048
June 18, 2009	June 18 and Dec 18	5 equal annual installments beginning June 18, 2017	7.97%	US$225,000	US$225,000	236,520
Oct 1, 2003	April 1 and Oct 1	5 equal annual installments beginning Oct 1, 2011	5.46%	US$54,000	US$32,400	34,059
June 19, 2002	June 19 and Dec 19	5 equal annual installments beginning June 19, 2010	6.62%	US$175,000	US$35,000	36,792
					Total Carrying Value	**$ 813,619**
					Current portion	**$ 48,145**
					Long term portion	**$ 765,474**

9. DECOMMISSIONING LIABILITY

Enerplus has estimated the net present value of its decommissioning liability to be $551,957,000 at June 30, 2013 compared to $599,652,000 at December 31, 2012, based on a total undiscounted liability of $744,791,000 and $659,714,000 respectively. The decommissioning liability was calculated using a risk free rate of 2.89% at June 30, 2013 (December 31, 2012 – 2.36%).

($ thousands)	Six months ended June 30, 2013	Year ended December 31, 2012
Decommissioning liability, beginning of year	$ 599,652	$ 563,763
Change in estimates	(50,610)	69,822
Property acquisition and development activity	2,509	5,559
	$ (48,101)	$ 75,381
Dispositions	(1,902)	(33,584)
Decommissioning expenditures	(6,335)	(19,905)
Accretion	6,822	13,522
Foreign currency translation adjustment	1,821	475
Decommissioning liability, end of period	**$ 551,957**	**$ 599,652**

At June 30, 2013 $6,562,000 of the total decommissioning liability above has been classified as liabilities associated with assets held for sale on the Consolidated Balance Sheet. Refer to Note 15 for further information.

10. FINANCE EXPENSE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2013	2012	2013	2012
Realized:				
Interest on bank debt and senior notes	$ 14,291	$ 13,427	$ 28,475	$ 24,275
Unrealized:				
Cross currency interest rate swap loss	488	284	822	1,733
Interest rate swap gain	(171)	(232)	(437)	(564)
Debt transaction cost amortization	615	414	1,230	794
Accretion of decommissioning liability	3,313	3,515	6,822	6,968
Finance expense	**$ 18,536**	**$ 17,408**	**$ 36,912**	**$ 33,206**

11. FOREIGN EXCHANGE

	Three months ended June 30,		Six months ended June 30,	
($ thousands)	2013	2012	2013	2012
Realized:				
Foreign exchange loss	$ 14,867	$ 11,188	$ 17,599	$ 5,908
Unrealized:				
Translation of U.S. dollar debt and working capital	12,218	11,920	16,538	9,555
Cross currency interest rate swap gain	(18,970)	(19,373)	(19,982)	(17,312)
Foreign exchange swap gain	(5,931)	(3,691)	(7,619)	(3,427)
Foreign exchange (gain)/loss	**$ 2,184**	**$ 44**	**$ 6,536**	**$ (5,276)**

12. INCOME TAXES

($ thousands)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Current tax expense/(recovery)				
Canada	$ 77	$ 510	$ 81	$ (123)
U.S.	1,324	3,335	2,627	4,671
Total current tax expense	$ 1,401	$ 3,845	$ 2,708	$ 4,548
Deferred tax expense	25,899	43,111	32,047	32,030
Total income tax expense	**$ 27,300**	**$ 46,956**	**$ 34,755**	**$ 36,578**

13. SHAREHOLDERS' CAPITAL

(a) Share Capital

	Six months ended June 30, 2013		Year ended December 31, 2012	
Authorized unlimited number of common shares **Issued:** (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	198,684	$ 3,818,043	181,159	$ 3,442,364
Issued for cash:				
Public offerings	–	–	14,709	330,618
Dividend reinvestment plan	–	–	955	19,150
Stock option plan	2	29	68	1,180
Non-cash:				
Stock dividend program	1,582	21,495	1,793	23,612
Stock option plan	–	3	–	1,119
Balance, end of period	**200,268**	**$ 3,839,570**	**198,684**	**$ 3,818,043**

(b) Dividends

($ thousands)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Cash dividends	$ 42,620	$ 83,156	$ 86,299	$ 189,151
Stock dividends	11,389	5,443	21,495	5,443
Dividends to shareholders	**$ 54,009**	**$ 88,599**	**$ 107,794**	**$ 194,594**

(c) Equity based compensation

The following table summarizes Enerplus' equity based compensation expense:

($ thousands)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Cash:				
Long term incentive plans expense/(recovery)	$ 3,687	$ (1,452)	$ 9,205	$ 131
Non-Cash:				
Stock option plan expense	2,951	2,117	5,478	5,109
Equity total return swap gain	(776)	(343)	(2,291)	(343)
Equity based compensation expense	**$ 5,862**	**$ 322**	**$ 12,392**	**$ 4,897**

(i) Long-Term Incentive Plans

Enerplus' long-term incentive plans include its PSU, RSU and DSU plans. At June 30, 2013 the long-term incentive plans had a liability balance of $16,939,000 (December 31, 2012 – $13,316,000) which is included in accounts payable on the Consolidated Balance Sheet.

The following table summarizes the PSU, RSU and DSU activity for the six months ended June 30, 2013:

(thousands of units)	PSUs	RSUs	DSUs
Units outstanding:			
Balance, beginning of year	605	963	35
Granted	361	444	78
Vested	–	(383)	(13)
Forfeited	(26)	(79)	–
Balance, end of period	**940**	**945**	**100**

(ii) Stock Option Plan

The following weighted average assumptions were used to arrive at the estimates of fair value during each of the respective reporting periods:

Weighted average for the period	Six months ended June 30, 2013	Year ended December 31, 2012
Dividend yield(1)	8.0%	8.2%
Volatility(1)	27.80%	28.35%
Risk-free interest rate	1.51%	1.35%
Forfeiture rate	10.0%	10.0%
Expected life	4.5 years	4.5 years

(1) Reflects the expected dividend yield and volatility of Enerplus shares over the life of the option.

The weighted average grant date fair value of options granted during the six months ended June 30, 2013 was $1.30 (June 30, 2012 – $2.52). At June 30, 2013, 5,632,000 options were exercisable at a weighted average exercise price of $24.30 with a weighted average remaining contractual term of 4.4 years, giving an aggregate intrinsic value of $1,429,000 (June 30, 2012 – $nil). The weighted average share price during the period was $14.34.

For the six months ended June 30, 2013, Enerplus expensed a total of $5,478,000 related to its stock option plan. The total unamortized fair value of outstanding options of $8,198,000 will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Six months ended June 30, 2013		Year ended December 31, 2012	
	Number of Options (000's)	Weighted Average Exercise Price(1)	Number of Options (000's)	Weighted Average Exercise Price(1)
Options outstanding				
Beginning of year	10,768	$ 22.11	5,098	$ 29.41
Granted	6,040	14.03	7,313	19.00
Exercised	(2)	13.78	(68)	17.35
Forfeited	(666)	20.46	(1,056)	24.92
Expired	–	–	(519)	44.67
End of period	**16,140**	**$ 19.16**	**10,768**	**$ 22.11**
Options exercisable at the end of period	**5,632**	**$ 24.30**	**2,558**	**$ 27.20**

(1) Exercise price reflects grant prices less any reduction in strike price for outstanding rights under the rights incentive plan.

The following tables summarize the Contributed Surplus activity for the six months ended June 30, 2013 and the ending balances as at June 30, 2013:

($ thousands)	Six months ended June 30, 2013	Year ended December 31, 2012
Balance, beginning of year	$ 36,088	$ 26,910
Stock Option Plan – exercised	(3)	(1,119)
Stock Option Plan – expensed	5,478	10,297
Balance, end of period	**$ 41,563**	**$ 36,088**

($ thousands)	June 30, 2013	December 31, 2012
Cancelled shares	$ 3,795	$ 3,795
Stock Option Plan	37,768	32,293
Balance, end of period	**$ 41,563**	**$ 36,088**

(d) Basic and Diluted Earnings Per Share

Net income per share has been determined based on the following:

	Three months ended June 30,		Six months ended June 30,	
(thousands of shares)	2013	2012	2013	2012
Weighted average shares	199,825	196,768	199,430	193,306
Dilutive impact of options	294	–	156	87
Diluted shares	**200,119**	**196,768**	**199,586**	**193,393**

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Carrying Value and Fair Value of Non-Derivative Financial Instruments

The carrying value of cash, accounts receivable, accounts payable, dividends payable and bank credit facilities approximated their fair value at June 30, 2013 and December 31, 2012 due to their short term nature. At June 30, 2013 the combined fair values of Enerplus' senior notes was $865,484,000 and the carrying value was $813,619,000 (December 31, 2012 – fair value of $896,871,000 and carrying value of $808,615,000). The fair value of the senior notes was estimated by discounting future interest and principal payments using available market information at the balance sheet date.

(b) Fair Value of Derivative Financial Instruments

Derivative instruments are recorded at their estimated fair value using observable market inputs, other than quoted prices, at the balance sheet date. 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 months ended June 30, 2013:

Deferred financial assets/(liabilities) ($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Equity Swaps	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Beginning of period	$ (213)	$ (33,482)	$ 9,277	$ (444)	$ 1,927	$ 21,095	$ (5,685)	$ (7,525)
Change in fair value gain/(loss)	171(1)	18,482(2)	5,931(3)	1,061(4)	776(5)	8,685(6)	12,837(6)	47,943
End of period	**$ (42)**	**$ (15,000)**	**$ 15,208**	**$ 617**	**$ 2,703**	**$ 29,780**	**$ 7,152**	**$ 40,418**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $18,970) and finance expense (loss of $488).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in equity based compensation.
(6) Recorded in commodity derivative instruments (see below).

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

Deferred financial assets/(liabilities) ($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Equity Swaps	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Beginning of period	$ (478)	$ (34,162)	$ 7,589	$ (853)	$ 412	$ 50,672	$ 3,349	$ 26,529
Change in fair value gain/(loss)	436(1)	19,162(2)	7,619(3)	1,470(4)	2,291(5)	(20,892)(6)	3,803(6)	13,889
End of period	**$ (42)**	**$ (15,000)**	**$ 15,208**	**$ 617**	**$ 2,703**	**$ 29,780**	**$ 7,152**	**$ 40,418**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (gain of $19,982) and finance expense (loss of $820).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in equity based compensation.
(6) Recorded in commodity derivative instruments (see below).

The following table summarizes the fair value as at June 30, 2013:

Balance Sheet Classification:	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swap	Equity Swap	Commodity Derivative Instruments Oil	Commodity Derivative Instruments Gas	Total
Assets:								
Current	$ –	$ 1,068	$ 409	$ 617	$ 970	$ 36,668	$ 8,315	$ 48,047
Long-term	–	–	14,799	–	1,733	–	–	16,532
Liabilities:								
Current	(42)	(16,068)	–	–	–	(6,888)	(1,163)	(24,161)
Total	**$ (42)**	**(15,000)**	**$ 15,208**	**$ 617**	**$ 2,703**	**$ 29,780**	**$ 7,152**	**$ 40,418**

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

($ thousands)	Three months ended June 30, 2013	Three months ended June 30, 2012	Six months ended June 30, 2013	Six months ended June 30, 2012
Change in fair value gain/(loss)	$ 21,522	$ 137,668	$ (17,089)	$ 120,642
Net realized cash gain/(loss)	9,100	5,042	20,656	(5,586)
Commodity derivative instruments gain/(loss)	**$ 30,622**	**$ 142,710**	**$ 3,567**	**$ 115,056**

(c) Risk Management

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 considered appropriate subject to a maximum of 80% of forecasted production volumes net of royalties.

The following tables summarize Enerplus' price risk management positions at July 22, 2013:

Crude Oil Instruments:

Instrument Type	bbls/day	US$/bbl[1]
Jul 1, 2013 – Jul 31, 2013		
WTI Swap	21,000	100.26
WTI Purchased Call	3,500	104.09
WTI Sold Put	5,500	63.09
WTI Sold Call	3,500	130.00
Brent – WTI Spread	5,000	7.09
WCS Differential Swap	2,000	(21.56)
MSW Differential Swap	500	(5.90)
Aug 1, 2013 – Dec 31, 2013		
WTI Swap	22,500	100.36
WTI Purchased Call	3,500	104.09
WTI Sold Put	5,500	63.09
WTI Sold Call	3,500	130.00
Brent – WTI Spread	5,000	7.09
WCS Differential Swap	2,000	(21.56)
MSW Differential Swap	500	(5.90)
Jan 1, 2014 – Jun 30, 2014		
WTI Swap	19,000	93.39
Brent – WTI Ratio Spread	2,000	92.90%
Jul 1, 2014 – Dec 31, 2014		
WTI Swap	14,000	92.61
Brent – WTI Ratio Spread	2,000	92.90%

(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, 2013 – Dec 31, 2013			
AECO Swap	28.4	3.61	
AECO Purchased Put	22.7	3.17	
Jan 1, 2014 – Dec 31, 2014			
AECO Swap	4.7	3.96	
Jul 1, 2013 – Dec 31, 2013			
NYMEX Swap	15.0		3.85
Jan 1, 2014 – Dec 31, 2014			
NYMEX Swap	50.0		4.17

Electricity Instruments:

Instrument Type	MWh	CDN$/MWh
Jul 1, 2013 – Dec 31, 2013		
AESO Power Swap(1)	12.0	63.81
Jan 1, 2014 – Dec 31, 2014		
AESO Power Swap(1)	12.0	53.69
Jan 1, 2015 – Dec 31, 2015		
AESO Power Swap(1)	6.0	50.38

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

15. ASSETS HELD FOR SALE

At June 30, 2013 certain non-core oil and gas properties were classified as assets held for sale. Enerplus expects these sales to close during the third quarter of 2013.

The carrying amounts reclassified on the Consolidated Balance Sheet are as follows:

($ thousands)	June 30, 2013
PP&E	$ 92,677
Accounts receivable	1,241
Assets held for sale	$ 93,918
Decommissioning liability	$ 6,562
Liabilities associated with assets held for sale	$ 6,562

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Boerne, Texas

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Canmore, Alberta

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Eric G. Le Dain
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Christopher M. Stephens
Vice President, Canadian Assets

P. Scott Walsh
Vice President, Information Systems

Kenneth W. Young
Vice President, Land

Michael R. Politeski
Treasurer & Corporate Controller

Edward L. McLaughlin
President, Enerplus Resources (USA) Corporation

(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
(7) Member of the Reserves Committee
(8) Chairman of the Reserves Committee
(9) Member of the Compensation & Human Resources Committee
(10) Chairman of the Compensation & Human Resources Committee
(11) Member of the Safety & Social Responsibility Committee
(12) Chairman of the Safety & Social Responsibility Committee

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.

D&P developed and producing

E&E exploration and evaluation

IFRS International Financial Reporting Standards

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

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

SDP stock dividend program

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

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

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