enerPLUS

FIRST QUARTER REPORT

THREE MONTHS ENDED MARCH 31, 2011

SELECTED FINANCIAL RESULTS

(in Canadian dollars)

	For the three months ended March 31, 2011	2010[1]
Financial (000's)		
Funds Flow[2]	**$ 161,224**	$ 198,281
Dividends to Shareholders	**96,686**	95,712
Net Income/(Loss)	**29,549**	(184,022)
Debt Outstanding – net of cash	**849,685**	517,263
Capital Spending	**174,444**	94,161
Property and Land Acquisitions	**48,218**	39,633
Divestments	**59,693**	1,538
Financial per Weighted Average Shares Outstanding		
Funds Flow[2]	**$ 0.90**	$ 1.14
Dividends	**0.54**	0.55
Net Income/(Loss)	**0.17**	(1.05)
Payout Ratio[2]	**60%**	48%
Adjusted Payout Ratio[2]	**169%**	96%
Selected Financial Results per BOE[3]		
Oil & Gas Sales[4]	**$ 46.92**	$ 47.65
Royalties	**(8.62)**	(8.57)
Commodity Derivative Instruments	**0.44**	0.51
Operating Costs	**(8.86)**	(9.91)
General and Administrative	**(3.28)**	(2.75)
Interest and Other Expenses	**(2.75)**	(0.93)
Taxes	**(0.12)**	–
Funds Flow	**$ 23.73**	$ 26.00
Weighted Average Number of Shares Outstanding	**178,832**	174,488
Debt to Trailing 12 Month Funds Flow	**1.2x**	0.7x[5]

SELECTED OPERATING RESULTS

	For the three months ended March 31, 2011	2010
Average Daily Production		
Natural gas (Mcf/day)	**251,480**	298,920
Crude oil (bbls/day)	**30,338**	30,974
NGLs (bbls/day)	**3,232**	3,925
Total (BOE/day)	**75,483**	84,719
% Natural gas	**56%**	59%
Average Selling Price[4]		
Natural gas (per Mcf)	**$ 3.91**	$ 5.10
Crude oil (per bbl)	**77.69**	73.86
NGLs (per bbl)	**60.29**	57.47
US$/CDN$ exchange rate	**1.02**	0.96
Net Wells drilled	**26**	137

(1) 2010 comparative amounts have been restated and are presented in accordance with International Financial Reporting Standards ("IFRS"). In addition, 2010 comparatives represent the results of Enerplus Resources Fund which converted into Enerplus Corporation on January 1, 2011.
(2) See "Non-GAAP Measures" in the Management's Discussion and Analysis.
(3) Non-cash amounts have been excluded.
(4) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.
(5) The 12 month trailing funds flow for March 31, 2010 includes funds flow for April through December 2009 which was prepared following previous Canadian GAAP and which has not been restated in accordance with IFRS.

Share Trading Summary **For the three months ended March 31, 2011**	**CDN* – ERF** (CDN$)	**U.S.** – ERF** (US$)
High	$ 32.83	$ 33.29
Low	$ 27.48	$ 27.75
Close	$ 30.71	$ 31.66

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

2011 Cash Dividends Per Share **Payment Month**	**CDN$**	**US$**
January	**$ 0.18**	**$ 0.18**
February	**0.18**	**0.18**
March	**0.18**	**0.19**
First Quarter Total	**$ 0.54**	**$ 0.55**

This interim report contains certain forward-looking information and statements. We refer you to the end of the accompanying Management's Discussion and Analysis under "Forward-Looking Information and Statements" for our disclaimers on forward-looking information and statements which apply to all other portions of this interim report. For information on the use of the term "BOE" see the introductory paragraph under the Management's Discussion and Analysis section in this interim report and the disclaimer at the end of the accompanying Management's Discussion and Analysis. All amounts in this interim report are in Canadian dollars unless otherwise specified.

PRESIDENT'S MESSAGE

I'm pleased to report that our operating and financial results for the first quarter of 2011 are on track with expectations. Strong crude oil prices continue to support our increased capital investment plans in both our Bakken and waterflood resource plays. With weak natural gas prices, however, we continue to proceed cautiously with investment, focusing on plays that have the best economics or where we believe there is opportunity for future value creation.

Daily production averaged 75,483 BOE/day during the quarter, within the range of our guidance expectations of 75,000 – 77,000 BOE/day despite challenges with extreme weather and unplanned downtime at a number of processing and gathering facilities. Production volumes were lower than in 2010 due to the sale of over 10,400 BOE/day of non-core production, a significant amount of which occurred late in the year. Approximately 44% of our total volumes were attributed to crude oil and natural gas liquids and we expect to see this percentage grow to 50% as we execute our development program in 2011 and 2012. We continue to see positive results from our drilling activities in our U.S. Bakken assets, our waterflood properties in Canada and also in the Marcellus. We invested just over $174 million in our assets during the quarter, drilling 25.7 net wells, however only 4.8 net wells were brought on-stream during the quarter. Approximately 80% of our capital was directed to these three key plays with over 55% of our capital directed toward oil projects. High industry activity levels in key growth areas such as the U.S. Bakken are extending timelines for execution of our development programs. To help ensure the timely execution of our plans over the next two years, we have entered into long-term agreements to secure drilling rigs and frac services in North Dakota and Montana.

We generated funds flow of $161.2 million during the quarter, virtually unchanged from the fourth quarter of 2010. Approximately 60% of funds flow was paid to shareholders through our monthly dividends of $0.18/share with the remainder reinvested into our asset base. We also utilized our bank credit facilities to fund a portion of our capital spending program during the quarter. When combining our dividend and our capital spending, our adjusted payout ratio was 169%, in line with our expectations. Our strategy throughout 2011 and 2012 is to increase our spending in earlier stage growth assets in order to increase future production and funds flow. As these plays continue to deliver results, we expect our payout ratio will decline in 2012 and beyond. We also sold undeveloped assets with no significant production or funds flow during the quarter through a series of transactions for approximately $60 million which helped moderate our use of debt. We continue to have a strong balance sheet with a debt-to-funds flow ratio of 1.2x at the end of the quarter providing us with the financial flexibility to execute our capital spending plans throughout 2011 and 2012.

Current wet weather conditions in a number of areas across the prairies and into North Dakota are hampering our ability to move rigs and execute our drilling programs. We expect capital spending during the second quarter will be lower, but anticipate increasing spending in the latter half of the year and continue to forecast full year capital spending of $650 million. We currently do not expect this to have a significant impact on our annual production results and our operating guidance remains unchanged for 2011. We continue to expect to produce on average 78,000 – 80,000 BOE/day increasing to 80,000 – 84,000 BOE/day as we exit the year.

PRODUCTION AND CAPITAL SPENDING for the three months ended March 31, 2011

Play Type	Average Daily Production	Capital Spending ($ millions)
Bakken/Tight Oil (BOE/day)	13,595	66,600
Crude Oil Waterfloods (BOE/day)	13,523	27,700
Conventional Oil (bbls/day)	6,537	2,800
Total Crude Oil & NGLs (BOE/day)	33,655	97,100
Marcellus Shale Gas (Mcfe/day)	21,272	41,800
Other Natural Gas (Mcfe/day)	229,690	35,500
Total Gas (Mcfe/day)	250,962	77,300
Company Total (BOE/day)	75,483	174,400

NET DRILLING ACTIVITY for the three months ended March 31, 2011

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in*	Wells Brought On-stream	Dry & Abandoned Wells
Bakken/Tight Oil	5.9	–	5.9	4.4	1.5	–
Crude Oil Waterfloods	8.5	0.3	8.8	6.7	2.1	–
Conventional Oil	1.0	–	1.0	–	1.0	–
Total Oil	**15.4**	**0.3**	**15.7**	**11.1**	**4.6**	**–**
Marcellus Shale Gas	5.1	–	5.1	5.1	–	–
Other Natural Gas	3.7	1.2	4.9	4.7	0.2	–
Total Gas	**8.8**	**1.2**	**10.0**	**9.8**	**0.2**	**–**
Company Total	**24.2**	**1.5**	**25.7**	**20.9**	**4.8**	**–**

* Wells pending potential completion/tie-in or abandonment and on-stream wells measured as at March 31, 2011

CRUDE OIL

Bakken/Tight Oil:

Activity in our Bakken/tight oil resource play was lower than anticipated during the first quarter of 2011. Severe winter weather conditions and high industry activity combined to limit access to trucks in the Williston Basin. As a result, we experienced some production shut-ins and delays in moving in rigs. These factors have led to a slighty slower ramp up in activity at Fort Berthold, North Dakota than originally expected. We had two rigs working throughout the quarter and drilled four horizontal wells – two Bakken short laterals and one Bakken long lateral and our first short Three Forks lateral well. Two Bakken wells (one short lateral and one long lateral) drilled in the fourth quarter of 2010 were completed in the first quarter. Initial production rates of the long lateral averaged 1,154 bbls/day during the first 30 days and the short lateral well averaged 885 bbls/day, our best short lateral well rate to date. We own an average 90% working interest at Fort Berthold.

The following table illustrates the average cumulative production from the long and short lateral wells drilled and completed by Enerplus versus our original type well expectations. Our well results to date have either met or exceeded our original estimates. On average, we are seeing lower decline rates on these wells after three months than originally expected. As well, after eight months, we have exceeded our type well estimates by more than 45% on the short laterals and more than 30% on the long lateral wells. Crude oil prices have strengthened over the last year as well, further improving the economics of these wells. Given the current commodity price environment, we expect long lateral wells to achieve payout on average in less than one year and short lateral wells to achieve payout in approximately 1.7 years.

Fort Berthold Cumulative Production Results To Date*

	30 Day Avg Cum. Prod/Well	60 Day Avg Cum. Prod/Well	120 Day Avg Cum. Prod/Well	180 Day Avg Cum. Prod/Well	240 Day Avg Cum. Prod/Well
Short Laterals					
Original Type Well Estimates (Mbbls)	17	26	40	50	59
Actual Well Results (Mbbls)	22	35	53	75	87
Number of Wells	6	5	5	4	4
Long Laterals					
Original Type Well Estimates (Mbbls)	34	53	81	103	121
Actual Well Results (Mbbls)	37	58	100	126	162
Number of Wells	5	5	3	3	2

* gross volumes and wells, prior to deduction of royalty interests

We currently have two rigs working at Sleeping Giant in Montana where we plan to drill seven horizontal wells this year. We plan to move two additional rigs into Fort Berthold in the second quarter and anticipate running with a minimum of four rigs for the remainder of the year. Planned infrastructure and gathering system build out continues to proceed at Fort Berthold. By mid-summer we expect to have a majority of our wells tied-in to a central gathering facility reducing our reliance on trucking in the region.

In total, we expect to drill and complete approximately 28 horizontal wells at Fort Berthold during the remainder of the year targeting both the Bakken and the Three Forks formations (75% long lateral wells) and will also be testing downspacing. With the additional rigs and our frac services agreement in place, drilling and completions activity has begun to accelerate and we should remain on schedule for the balance of the year, drilling and completing two to four wells per month. High activity levels in the region may continue to put upward pressure on costs, however, we continue to expect to spend approximately $250 million in North Dakota and Montana in 2011.

Production volumes averaged approximately 13,600 BOE/day, unchanged from volumes reported at year end. Since acquiring our interests and assuming operatorship approximately one year ago, we have drilled eight horizontal wells in the Fort Berthold area and completed another four wells drilled by the previous operator. Production has grown from approximately 1,100 bbls/day to over 4,500 bbls/day primarily as a result of our successful drilling activities.

Waterfloods:

Production from our waterflood properties was on track with our expectations for the first quarter averaging approximately 13,500 BOE/day. We spent approximately $28 million on drilling, completions and facilities during the quarter. We drilled 8.8 net wells primarily targeting light oil in the Cardium and the Ratcliffe.

At our Pembina Cardium waterflood, we successfully completed the drilling of a six well program and completed three of these wells during the quarter. We are currently evaluating the results from these wells and early indications are positive. In Saskatchewan, we drilled and completed three horizontal wells into the Ratcliffe trend at our Freda Lake waterflood. Initial 30 day production results are meeting expectations ranging from 200 - 300 bbls/day from each well. Our battery expansion at Freda Lake was completed and we have an additional 11 wells planned this year. Activities at our Giltedge polymer project continued during the quarter. We began injection on schedule in April and expect to see first production response sometime in the fourth quarter. Work is also underway at our second polymer project at Medicine Hat with start-up planned for early 2012. At year end, Enerplus had identified incremental and enhanced oil recovery potential of over 60 million BOE of contingent resources associated with a portion of our waterflood portfolio, providing over 70% upside to our proved plus probable waterflood reserves at December 31, 2010.

NATURAL GAS

Marcellus:

The Marcellus play area continued to be very active through the first quarter of 2011 as our partners continued to drill wells to retain and develop leases. We are experiencing positive drilling results and better than expected decline rates on our base production with volumes for the first quarter slightly ahead of expectations averaging 21.3 MMcfe/day up from 2010 exit volumes of 17.6 MMcfe/day net to Enerplus.

We participated in drilling 21 gross wells (approximately 5 net) with our partners Chief Oil & Gas and Exco during the quarter. The majority of this activity was in northeastern Pennsylvania where initial production rates and expected ultimate recoveries have been generally above our type curve. Completion and tie-in activities were slower than anticipated with only one net non-operated well completed due to winter weather conditions and continued delays with pipeline construction. We currently have 52 gross wells on production with over 70% of our production volumes from wells drilled in the northeastern region of Pennsylvania. Another 48 gross wells are either waiting on completion or are in the process of completion and a further 20 gross wells are waiting on tie-in. We continue to expect a significant level of drilling activity in 2011 focusing on lease retention and delineation drilling. We currently have ten rigs operating in the play, nine with our partners plus one operated rig.

The table below illustrates the cumulative performance of the majority of wells that are currently on production. Production from northeastern Pennsylvania counties has either met or exceeded our estimates with Susquehanna county wells materially outperforming the type curve the longer the wells are on production. The production volumes presented do not include any associated natural gas liquids. While the volumes in

Marshall and Greene Counties appear to be slightly under our type well expectations, the associated natural gas liquids in this area, combined with lower well costs support economic returns for these wells.

Marcellus Cumulative Production Results*

	30 Day Avg Cum. Prod/Well	60 Day Avg Cum. Prod/Well	90 Day Avg Cum. Prod/Well	120 Day Avg Cum. Prod/Well	180 Day Avg Cum. Prod/Well
NE Pennsylvania – Susquehanna County					
Type Well Estimate (MMcf)	169	310	431	539	725
Actual (MMcf)	195	431	685	910	1,347
Well Count	4	4	3	3	3
NE Pennsylvania – Lycoming County					
Type Well Estimate (MMcf)	142	260	361	451	608
Actual (MMcf)	101	213	329	433	622
Well Count	19	19	18	16	15
NE Pennsylvania – Bradford County					
Type Well Estimate (MMcf)	130	238	331	414	557
Actual (MMcf)	80	199	317	435	622
Well Count	13	13	13	10	4
W. Virginia/ SW PA – Marshall/Greene County					
Type Well Estimate (MMcf)	115	210	292	365	492
Actual (MMcf)	98	180	262	344	467
Well Count	11	11	11	9	6

* of horizontal wells only and gross volumes before deduction of royalty interests.

On our operated leases, we are planning a modest delineation program in 2011 focusing on our acreage in central Pennsylvania and Preston County, West Virginia. We successfully completed our first operated well in Clinton County (5,300 foot lateral length with an eight stage frac) which had a peak test rate of approximately 3.8 MMcf/day. With the lack of pipeline infrastructure in this area, we do not expect to tie-in this well until early 2012. We also began drilling the first of two wells in Centre County in Pennsylvania and will follow these wells with three wells in the southern part of Preston County in West Virginia.

Other Natural Gas:

Activities on our Canadian natural gas assets were mainly related to non-operated drilling in the liquids rich Deep Basin area. We participated in a total of eight gross non-operated wells (2.4 net wells) in this area and also finished our operated two well program at Tommy Lakes. Well results from our non-operated partners have been encouraging particularly as a number of these wells are close to our Ansell/Minehead properties. Given the positive drilling results to date, we expect further drilling activity by our partners in this region and will continue to assess this activity as it relates to our surrounding lands. We expect to allocate some additional capital to delineate a portion of our Stacked Mannville lands. Enerplus currently holds over 80,000 net acres of operated land prospective for either the Montney or the Stacked Mannville.

SUMMARY

2011 will be a very active year for Enerplus as we execute one of our largest capital programs in our history. In April we announced a number of changes to our senior leadership team, including the promotion of Mr. Ian Dundas to the position of Executive Vice-President and Chief Operating Officer. I am confident that our leadership team, combined with the technical and commercial acumen of our staff, can deliver results. Our foundation of mature assets is providing us with a stable platform to support our business strategy. We are actively pursuing our development plans in new growth plays and are encouraged by our results to date. With our successful conversion to a corporation effective January 1, 2011, we are confident that we can create value for our shareholders through our growth and income strategy.

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation

The following discussion and analysis of financial results is dated May 12, 2011 and is to be read in conjunction with:

- the audited consolidated financial statements of Enerplus Resources Fund (the"Fund") as predecessor to Enerplus Corporation ("Enerplus" or the "Company"), as at and for the years ended December 31, 2010 and 2009; and
- the unaudited interim consolidated financial statements of Enerplus Corporation as at and for the three months ended March 31, 2011 and 2010.

On January 1, 2011, the Fund converted from an income trust into a corporate entity with Enerplus Corporation being the successor issuer to the Fund. References in this MD&A to common shares, shareholders and dividends as they relate to the comparative periods reflect the history of the Fund and, therefore, reflect trust units, trust unitholders and distributions, respectively.

The Company is required to apply International Financial Reporting Standards ("IFRS") for financial periods beginning on January 1, 2011, including comparative amounts for the respective periods in 2010 and an opening balance sheet as at January 1, 2010. As a result (except where specifically referenced herein), this MD&A references financial statements prepared in accordance with IFRS including comparative prior period amounts. Readers are encouraged to refer to Note 15 of the interim consolidated financial statements for more information.

All amounts are stated in Canadian dollars unless otherwise specified and all note references relate to the notes included with the Company's unaudited interim consolidated financial statements as at and for the three months ended March 31, 2011. 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 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. Use of BOE and Mcfe in isolation may be misleading.

The following MD&A contains forward-looking information and statements. We refer you to the end of the MD&A under "Forward-Looking Information and Statements" for our disclaimer.

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 IFRS and therefore may not be comparable with the calculation of similar measures by other entities:

"Funds flow" is a term used to evaluate operating performance and assess leverage. Enerplus considers funds flow an important measure of its ability to generate funds necessary to finance dividends, operating activities, capital expenditures and debt repayments. Funds flow is calculated based on cash flow from operating activities before changes in non-cash operating working capital and decommissioning liabilities settled. Funds flow as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles cash flow from operating activities to funds flow:

	Three months ended March 31,	
(CDN$ thousands)	**2011**	**2010**
Cash flow from operating activities	**132,403**	186,628
Decommissioning liabilities settled	**4,210**	4,291
Changes in non-cash operating working capital	**24,611**	7,362
Funds Flow	**161,224**	198,281

"Payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing dividends to shareholders by funds flow.

"Adjusted payout ratio" is used to analyze operating performance, leverage and liquidity. We calculate adjusted payout ratio as dividends to shareholders 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 first quarter operating results were in-line with expectations with production averaging 75,483 BOE/day, operating expenses of $8.40/BOE, and capital spending of $174.4 million. We recognized proceeds of $59.7 million during the quarter on dispositions of non-core properties with minimal production and reserves. Although our operations are on track, lower natural gas prices and decreased production levels as a result of our 2010 dispositions reduced funds flow by 19% to $161.2 million compared to the first quarter of 2010. Monthly dividends were maintained at $0.18/share for the quarter resulting in a payout ratio and adjusted payout ratio of 60% and 169% respectively. Capital spending during the quarter included investments in early stage resource plays that did not generate immediate production or funds flow, resulting in a higher adjusted payout ratio for the period. We expect our payout ratios will decline in 2012 and beyond as these growth plays deliver results.

We are maintaining all of our previous guidance targets with the exception of a small increase in non-cash general and administrative expenses per BOE as a result of IFRS accounting.

RESULTS OF OPERATIONS

Production

Production in the first quarter averaged 75,483 BOE/day, in-line with expectations despite challenges related to weather and plant outages, both of which impacted our ability to get production to sales points. We continue to see positive results from our capital programs at Marcellus, Fort Berthold and our Canadian oil drilling programs. Compared to the first quarter of 2010, production decreased 11% or 9,236 BOE/day, which is consistent with our expectations given the sale of approximately 10,400 BOE/day of non-core production during 2010. Based on our capital spending plans for 2011, we expect production levels to increase throughout the year with annual average production of 78,000 to 80,000 BOE/day and an exit rate of 80,000 to 84,000 BOE/day. This guidance does not contemplate any further acquisition or divestment activity.

Average daily production volumes for the three months ended March 31, 2011 and 2010 are outlined below:

	Three months ended March 31,		
Average Daily Production Volumes	**2011**	**2010**	**% Change**
Natural gas (Mcf/day)	**251,480**	298,920	(16)%
Crude oil (bbls/day)	**30,338**	30,974	(2)%
Natural gas liquids (bbls/day)	**3,232**	3,925	(18)%
Total daily sales (BOE/day)	**75,483**	84,719	(11)%

Pricing

The prices received for our natural gas and crude oil production directly impact our earnings, funds flow and financial condition. The following table compares our average selling prices for the three months ended March 31, 2011 and 2010. It also compares the benchmark price indices for the same periods.

	Three months ended March 31,		
Average Selling Price(1)	**2011**	**2010**	**% Change**
Natural gas (per Mcf)	**$ 3.91**	$ 5.10	(23)%
Crude oil (per bbl)	**77.69**	73.86	5%
Natural gas liquids (per bbl)	**60.29**	57.47	5%
Per BOE	**46.92**	47.65	(2)%

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

Average Benchmark Pricing	Three months ended March 31, 2011	2010	% Change
AECO natural gas – monthly index (CDN$/Mcf)	**$ 3.77**	$ 5.36	(30)%
AECO natural gas – daily index (CDN$/Mcf)	**3.76**	4.95	(24)%
NYMEX natural gas – monthly NX3 index (US$/Mcf)	**4.14**	5.38	(23)%
NYMEX natural gas – monthly NX3 index CDN$ equivalent (CDN$/Mcf)	**4.06**	5.60	(28)%
WTI crude oil (US$/bbl)	**94.10**	78.72	20%
WTI crude oil CDN$ equivalent (CDN$/bbl)	**92.25**	82.00	13%
US$/CDN$ exchange rate	**1.02**	0.96	6%

Winter weather was colder than normal across most of North America, however the continued over supply of U.S. domestic gas production kept natural gas prices depressed. During the first quarter of 2011 the average of the AECO monthly and daily gas price indices increased 5% to $3.77/Mcf compared to the fourth quarter of 2010.

During the quarter, we realized an average price on our natural gas sales of $3.91/Mcf (net of transportation costs), a decrease of 23% from $5.10/Mcf for the same period in 2010. The majority of our natural gas sales are priced with reference to either the monthly or daily AECO indices. The changes experienced in our realized prices are comparable to the indices' changes for the three months ended March 31, 2011.

The West Texas Intermediate ("WTI") crude oil price continued to increase during the quarter and averaged US$94.10/bbl compared to $78.72/bbl during the same period in 2010. In Canadian dollars, WTI increased 13% to $92.25/bbl from $82.00/bbl for the same period in 2010. Our average realized crude oil sales price was $77.69/bbl (net of transportation costs) for the first quarter, a 5% increase from $73.86/bbl during the same period in 2010. Our first quarter realized price did not increase as much as the benchmark expressed both in Canadian and U.S. dollars due to the significant increase in light/heavy oil price differentials compared to the same period in 2010. Heavy crude oil differentials widened during the first quarter as more heavy crudes came to the market due to the disruptions caused by the Husky Upgrader fire. Our Canadian crude was bottlenecked as a result of the Enbridge Line 6B pipeline problems, which lowered realized prices, and our U.S. crude oil production was impacted by the increased transportation costs incurred due to pipeline capacity constraints in North Dakota and Montana.

The Canadian dollar strengthened 6% against the U.S. dollar during the first quarter of 2011 compared to the same period in 2010. As most of our crude oil and natural gas is priced in reference to U.S. dollar denominated benchmarks, this movement in the exchange rate decreased the Canadian dollar prices that we would have otherwise realized.

Price Risk Management

We continue to adjust our price risk management program with consideration given to our overall financial position together with the economics of our capital program and potential acquisitions. Consideration is also given to the costs of our risk management program as we seek to limit our exposure to price downturns. During the quarter we continued to add crude oil hedge positions for 2012 but did not add any additional natural gas positions due to low forward prices for natural gas. At March 31, 2011 we have no commodity derivative contracts outstanding related to our natural gas production. See Note 14 for a detailed list of our current price risk management positions.

The following is a summary of the financial contracts in place at May 4, 2011 expressed as a percentage of our anticipated net production volumes:

	Crude Oil (US$/bbl)	
	April 1, 2011 – December 31, 2011	January 1, 2012 – December 31, 2012
Purchased Puts (downside protection)	–	$ 103.00
%	–	3%
Sold Puts (limiting downside protection)	$ 56.50	$ 65.00
%	12%	3%
Swaps (fixed price)	$ 87.27	$ 97.64
%	61%	30%
Sold Calls (capped price)	–	$ 133.00
%	–	3%
Purchased Calls (repurchasing upside)	$ 101.17	–
%	12%	–

Based on weighted average price (before premiums), estimated average annual production of 78,000 to 80,000 BOE/day for 2011 and 83,000 to 85,000 BOE/day for 2012, net of royalties of 20%.

Accounting for Price Risk Management

During the first quarter of 2011 our price risk management program generated cash gains of $13.3 million on our natural gas contracts and cash losses of $10.3 million on our crude oil contracts. In comparison, during the first quarter of 2010 we experienced cash gains of $8.0 million on our natural gas contracts and cash losses of $4.1 million on our crude oil contracts. The cash gains in 2011 are due to natural gas contracts which provided floor protection above market prices whereas the cash losses are a result of crude oil prices rising above our swap positions.

As the forward markets for natural gas and crude oil fluctuate, 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 March 31, 2011 the fair value of our crude oil derivative instruments, net of premiums, represented a loss of $104.9 million which is recorded as a current deferred financial liability on our balance sheet. At December 31, 2010 the fair value of our natural gas and crude oil derivative instruments represented a gain of $12.6 million and a loss of $38.3 million respectively. The change in the fair value of our commodity derivative instruments during 2011 resulted in unrealized losses of $12.6 million for natural gas and $66.5 million for crude oil. See Note 14 for details.

The following table summarizes the effects of our commodity derivative instruments on income:

Risk Management Gains/(Losses) ($ millions, except per share amounts)	Three months ended March 31, 2011		Three months ended March 31, 2010	
Cash gains/(losses):				
Natural Gas	**$ 13.3**	$ 0.59/Mcf	$ 8.0	$ 0.30/Mcf
Crude Oil	**(10.3)**	$ (3.77)/bbl	(4.1)	$ (1.47)/bbl
Total cash gains/(losses)	**$ 3.0**	$ 0.44/BOE	$ 3.9	$ 0.51/BOE
Non-cash gains/(losses) on financial contracts:				
Change in fair value – natural gas	**$ (12.6)**	$ (0.56)/Mcf	$ 36.0	$ 1.34/Mcf
Change in fair value – crude oil	**(66.5)**	$ (24.36)/bbl	(6.6)	$ (2.37)/bbl
Total non-cash gains/(losses)	**$ (79.1)**	$ (11.60)/BOE	$ 29.4	$ 3.86/BOE
Total gains/(losses)	**$ (76.1)**	$ (11.16)/BOE	$ 33.3	$ 4.37/BOE

Revenues

Crude oil and natural gas revenues in the first quarter of 2011 were $318.7 million ($324.0 million, net of $5.3 million of transportation costs), a decrease of 12% or $44.6 million compared to $363.3 million ($369.7 million, net of $6.4 million of transportation costs) in the first quarter of 2010. This decrease was primarily due to lower production resulting from our 2010 dispositions and lower natural gas prices, partially offset by higher crude oil prices.

Analysis of Sales Revenue[(1)] ($ millions)	**Crude Oil**	**NGLs**	**Natural Gas**	**Total**
Quarter ended March 31, 2010	$ 205.9	$ 20.3	$ 137.1	$ 363.3
Price variance[(1)]	10.4	0.8	(26.5)	(15.3)
Volume variance	(4.2)	(3.6)	(21.5)	(29.3)
Quarter ended March 31, 2011	**$ 212.1**	**$ 17.5**	**$ 89.1**	**$ 318.7**

(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 months ended March 31, 2011 and 2010, royalties were $58.6 million and $65.4 million respectively, representing approximately 18% of oil and gas sales, net of transportation costs. We continue to expect annual royalties of approximately 20% of oil and gas sales, net of transportation costs.

Operating Expenses

Operating expenses for the first quarter of 2011 were $57.1 million or $8.40/BOE compared to $75.9 million or $9.96/BOE for the same period in 2010. Operating costs have decreased in 2011 mainly due to the divestment of higher operating cost properties throughout 2010. During the first quarter of 2011 higher Alberta electricity costs were largely offset by realized cash gains on our electricity contracts. We also recorded a non-cash mark to market gain of $3.1 million on our electricity contracts given the increase in forward electricity prices at period end. In comparison, we recorded a non-cash mark to market loss of $0.4 million on our electricity contracts during the first quarter of 2010.

Although our first quarter results benefited from gains on our electricity contracts, we are maintaining our annual guidance for operating costs of approximately $9.20/BOE.

Netbacks

The following tables outline our crude oil and natural gas netbacks for the three months ended March 31, 2011 and 2010. Natural gas liquids are included with the respective well or property and converted to BOE or Mcfe depending on the dominant production category.

	Three months ended March 31, 2011		
	Crude Oil	Natural Gas	Total
Average Daily Production	33,655 BOE/day	250,962 Mcfe/day	75,483 BOE/day
Netback ($ millions)			
Revenue[(1)]	$ 217.5	$ 101.2	$ 318.7
Royalties	(47.9)	(10.7)	(58.6)
Cash operating costs	(29.2)	(31.0)	(60.2)
Netback before hedging	**$ 140.4**	**$ 59.5**	**$ 199.9**
Realized gain/(loss) on commodity derivatives	(10.3)	13.3	3.0
Netback after hedging	**$ 130.1**	**$ 72.8**	**$ 202.9**
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[(1)]	$ 71.81	$ 4.48	$ 46.92
Royalties	(15.79)	(0.48)	(8.62)
Cash operating costs	(9.63)	(1.37)	(8.86)
Netback before hedging	**$ 46.39**	**$ 2.63**	**$ 29.44**
Realized gain/(loss) on commodity derivatives	(3.39)	0.59	0.44
Netback after hedging	**$ 43.00**	**$ 3.22**	**$ 29.88**

Approximately 45% of our production in the first quarter of 2011 was from crude oil properties whereas this represented 70% of our operating netback before hedging. This reflects the strength of crude oil prices relative to natural gas prices.

	Three months ended March 31, 2010		
	Crude Oil	Natural Gas	Total
Average Daily Production	34,840 BOE/day	299,274 Mcfe/day	84,719 BOE/day
Netback ($ millions)			
Revenue[(1)]	$ 210.0	$ 153.3	$ 363.3
Royalties	(47.5)	(17.9)	(65.4)
Cash operating costs	(38.3)	(37.3)	(75.6)
Netback before hedging	**$ 124.2**	**$ 98.1**	**$ 222.3**
Realized gain/(loss) on commodity derivatives	(4.1)	8.0	3.9
Netback after hedging	**$ 120.1**	**$ 106.1**	**$ 226.2**
Netback $ per BOE or Mcfe	(per BOE)	(per Mcfe)	(per BOE)
Revenue[(1)]	$ 66.96	$ 5.69	$ 47.65
Royalties	(15.15)	(0.66)	(8.57)
Cash operating costs	(12.19)	(1.39)	(9.91)
Netback before hedging	**$ 39.62**	**$ 3.64**	**$ 29.17**
Realized gain/(loss) on commodity derivatives	(1.30)	0.30	0.51
Netback after hedging	**$ 38.32**	**$ 3.94**	**$ 29.68**

(1) Net of oil and gas transportation costs

General and Administrative Expenses ("G&A")

During the first quarter of 2011 G&A expenses totaled $25.7 million or $3.79/BOE compared to $20.3 million or $2.66/BOE in the first quarter of 2010. Approximately $4.2 million of the $5.4 million increase is related to the IFRS accounting treatment for our rights incentive plan which was the predecessor to our stock option plan. Under the income trust structure our trust unit rights were considered liabilities pursuant to IFRS and were recorded on the balance sheet at fair value with changes in fair value recorded through earnings. The gain of $0.7 million in the first quarter of 2010 reflected the decrease in fair value of our outstanding rights. The increase in our trading price during the second half of 2010 resulted in a significant increase in the fair value of our outstanding rights and the corresponding non-cash cost of the plan. Upon conversion to a corporation, our rights became equity for accounting purposes and the outstanding liability was reclassified to contributed surplus with the remaining unamortized fair value charged to net income as non-cash G&A over the remaining vesting period of the rights. This accounting treatment has increased our 2011 non-cash G&A relative to prior year levels and it will continue to impact G&A over the remaining vesting period of the rights.

For stock option grants in 2011 onward, we are using the Black Scholes model to calculate the grant date fair value which is expensed over the vesting period of the options. See Note 13 for further details.

Our cash G&A increased by $1.2 million or 6% in the first quarter of 2011 compared to the first quarter of 2010 due to higher compensation costs. On a BOE basis our cash G&A increased $0.53/BOE or 19% which reflects lower production levels during 2011 resulting from our 2010 asset divestments.

The following table summarizes the cash and non-cash expenses recorded in G&A:

General and Administrative Costs ($ millions)	**Three months ended March 31, 2011**	**2010**
Cash G&A	**$ 22.2**	$ 21.0
Stock option plan (non-cash)	**3.5**	(0.7)
Total G&A	**$ 25.7**	$ 20.3
(Per BOE)	**2011**	**2010**
Cash G&A	**$ 3.28**	$ 2.75
Stock option plan (non-cash)	**0.51**	(0.09)
Total G&A	**$ 3.79**	$ 2.66

We are increasing our 2011 non-cash G&A guidance by $0.15/BOE to $0.45/BOE, solely as a result of the IFRS accounting treatment for our trust unit rights plan. There is no change to our cash G&A guidance of $3.00/BOE and as a result our total G&A guidance is now $3.45/BOE.

Finance Expense

Finance expense includes cash interest costs on our senior notes and bank credit facility. Non-cash amounts recorded in finance expense include accretion of decommissioning liabilities, amortization of financing fees and premiums, along with 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.

Interest on our senior notes and bank debt for the three months ended March 31, 2011 totaled $11.9 million compared to $9.2 million for the same quarter of 2010. The increase is primarily due to higher bank debt outstanding along with higher drawn and undrawn fees compared to the first quarter of 2010.

The following table summarizes the cash and non-cash finance expense recorded.

Finance Expense ($ millions)	**Three months ended March 31, 2011**	**2010**
Interest on senior notes and bank credit facility	**$ 11.9**	$ 9.2
Non-cash finance expense	**2.1**	4.7
Total Finance Expense	**$ 14.0**	$ 13.9

At March 31, 2011 approximately 51% of our debt was based on fixed interest rates while 49% had floating interest. In comparison, at March 31, 2010 approximately 77% of our debt was based on fixed interest rates and 23% was floating.

Foreign Exchange

We recorded a foreign exchange loss of $1.7 million during the quarter compared to a gain of $10.4 million during the first quarter of 2010. In both the first quarter of 2011 and 2010 the Canadian dollar strengthened relative to the U.S. dollar, however, in 2011 we had a net U.S. dollar receivable balance from our U.S. subsidiary versus a net U.S. dollar payable balance in 2010. As a result, we had a realized loss of $7.3 million during the first quarter of 2011 compared to a realized gain of $2.4 million during the same period in 2010.

Net unrealized gains totaled $5.6 million during the first quarter of 2011 compared to $8.0 million during the first quarter of 2010. The translation of our U.S. dollar denominated debt resulted in unrealized gains of $11.9 million in the first quarter of 2011 compared to $15.4 million during the same period in 2010. However, the change in fair value of our foreign exchange swaps and CCIRS resulted in unrealized losses of $6.3 million for the quarter compared to $7.4 million during the first quarter of 2010.

Foreign Exchange ($ millions)	**Three months ended March 31, 2011**	**2010**
Realized loss/(gain)	**$ 7.3**	$ (2.4)
Unrealized loss/(gain)	**(5.6)**	(8.0)
Total Foreign Exchange loss/(gain)	**$ 1.7**	$ (10.4)

Exploration & Evaluation Assets

Exploration and Evaluation ("E&E") assets are assets that management has not fully evaluated for technical feasibility and commercial viability. When an asset or area is determined to be technically feasible and commercially viable, the accumulated costs are tested for impairment and then transferred to Property, Plant and Equipment ("PP&E") as Developed and Producing ("D&P") assets. During the quarter our primary E&E assets consisted of our Marcellus and Fort Berthold assets in the U.S., along with various Bakken and Deep Basin assets in Canada. Our Kirby oil sands asset was classified as an E&E asset up until its sale in October 2010.

Approximately $705.0 million of E&E assets were transferred to PP&E as D&P assets during the first quarter of 2011. These transferred assets consisted of $693.3 million of Fort Berthold assets and $11.7 million of Marcellus assets. Based on the results of our capital programs at Fort Berthold over the past two years and associated reserve additions, management concluded that the overall play has become a development asset and therefore transferred all costs to PP&E. New projects at Fort Berthold targeting the Bakken formation will be recorded directly to D&P assets within PP&E and will not be considered E&E. A portion of the Marcellus assets were transferred to PP&E along with the associated acquisition costs. As we continue our delineation activities in the Marcellus we expect to transfer more of our Marcellus assets from E&E to D&P.

Capital Investment

Capital spending for the first quarter of 2011 was in-line with expectations at $174.4 million, compared to $94.2 million for the same period in 2010. Activity during the quarter focused predominantly on our key resource plays with $66.6 million directed towards Bakken/tight oil assets, $27.7 million for crude oil waterfloods and $41.8 million in our Marcellus shale gas play in the U.S.

Property and land acquisitions for the first quarter of 2011 totaled $48.2 million compared to $39.6 million for the same period in 2010. The majority of the acquisitions in 2011 related to acquiring undeveloped land in Canada and the U.S. for $18.2 million, as well as US$29.9 million related to our Marcellus carry obligation. Our remaining carry obligation at March 31, 2011 was US$117.1 million. Acquisitions in the first quarter of 2010 were primarily focused in the Marcellus with land acquisitions of $23.9 million and US$9.0 million related to our carry obligation.

Our total capital investments for the first quarter of 2011 and 2010 are outlined below:

Capital Investment ($ millions)	Three months ended March 31, 2011	2010
E&E assets	**$ 95.3**	$ 35.5
D&P assets	**79.1**	58.7
Capital Spending	**174.4**	94.2
Office Capital	**1.6**	0.5
Sub-total	**176.0**	94.7
E&E assets	**47.5**	31.8
D&P assets	**0.7**	7.8
Property and Land Acquisitions	**48.2**	39.6
Property Dispositions	**(59.7)**	(1.5)
Total Net Capital Investment	**$ 164.5**	$ 132.8

Looking forward we expect capital spending in the second quarter to be lower than planned due to a delayed spring break-up and wet weather conditions in many areas that has impacted our ability to move rigs and equipment. Activity levels in the Marcellus and Fort Berthold areas remain very high and access to services and supplies continues to challenge the timing and execution of our programs in these areas. We have entered into contracts to secure drilling and related fracturing services for two years for our U.S. Bakken play. We are maintaining our 2011 guidance of $650 million for annual capital spending, and don't expect the timing to impact annual or exit production.

Dispositions

During the quarter we disposed of non-core assets with minimal production and reserves for total proceeds of $59.7 million. Under IFRS we recognized a gain of $26.2 million on these dispositions. Under previous Canadian GAAP these types of gains and losses were generally not recognized.

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

DD&A of PP&E is recognized using the unit-of-production method based on proved plus probable reserves. For the three months ended March 31, 2011 DD&A totaled $99.9 million or $14.70/BOE compared to $118.1 million or $15.49/BOE during the same period in 2010. The decrease in depletion per BOE is primarily due to the impact of impairments recorded to PP&E assets during 2010.

Impairments

On transition to IFRS, the majority of our goodwill in Canada was allocated to our Canadian natural gas focused Cash Generating Units ("CGUs"). As commodity price forecasts fluctuate, impairment tests are carried out on CGUs to determine if D&P asset carrying values, including goodwill, are impaired. Any calculated impairments are allocated to goodwill first, with the remainder recorded against the carrying value of the D&P asset.

D&P asset impairments of $32.4 million were recognized during the first quarter of 2011 in certain Canadian natural gas focused CGUs due to lower natural gas price forecasts. Since no goodwill balance remained in these CGUs at March 31, 2011, no impairments were recorded to goodwill. Similarly, impairments were also recognized during the first quarter of 2010 totaling $297.6 million, of which $260.8 million was recorded against goodwill and $36.8 million against D&P assets.

Impairments ($ millions)	Three months ended March 31, **2011**	**2010**
Goodwill impairments	**$ –**	$ 260.8
D&P impairments	**32.4**	36.8
Total Impairments	**$ 32.4**	$ 297.6

Goodwill

The goodwill balance of $147.9 million at March 31, 2011 consists of $145.2 million related to our U.S. CGUs and $2.7 million related to our Canadian CGUs. The goodwill balance with respect to our U.S. operations is exposed to foreign currency fluctuations as it is translated into Canadian dollars at the period end exchange rate.

Decommissioning Liabilities

In connection with our operations, we incur abandonment and reclamation costs related to our assets including 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 liabilities to be $373.0 million at March 31, 2011 which represents a $19.7 million decrease from $392.7 million at December 31, 2010. The majority of this decrease relates to the increase in the risk free rate used to calculate the present value of the future cash outflows, which rose from 3.52% at December 31, 2010 to 3.75% at March 31, 2011. See Note 9 for further information.

Taxes

Deferred Income Taxes

Our deferred income tax recovery was $50.4 million for the quarter ended March 31, 2011 compared to a recovery of $0.4 million for the same period in 2010. The increase is primarily due to a $34.0 million recovery related to our conversion to a corporation on January 1, 2011 which reduced the deferred tax rate applicable to certain temporary differences. In addition we recorded a $9.0 million recovery for the recognition of previously unrecognized tax losses.

Current Income Taxes

Effective January 1, 2011 we became subject to normal Canadian corporate taxes as a result of our conversion to a corporation. However, we currently do not expect to pay material cash taxes in Canada prior to 2015 as we have sufficient tax pools to offset our anticipated taxable income prior to that time. This estimate may vary depending on numerous factors, including fluctuating commodity prices and unplanned acquisition and disposition activity.

The amount of current taxes recorded with respect to our U.S. operations is dependent upon income levels and the timing of both capital expenditures and the repatriation of funds to Canada. For the first quarter of 2011 we recorded $0.8 million of current U.S. income tax expense (2010 – nil). We continue to expect to pay a nominal amount of U.S. cash taxes in 2011.

Net Income

Net income for the first quarter of 2011 was $29.5 million or $0.17 per share compared to a net loss of $184.0 million or $1.05 per share for the same period in 2010. The $213.5 million change in net income was primarily due to a $260.8 million goodwill impairment expense recorded in the first quarter of 2010, combined with an increase in deferred income tax recoveries of $50.0 million, lower DD&A expense of $18.2 million and lower operating costs of $18.9 million during the first quarter of 2011. These increases to net income were partially offset by an increase in commodity derivative instrument losses of $109.5 million and lower oil and gas sales revenue (net of transportation) of $44.6 million.

Cash Flow from Operating Activities

Cash flow from operating activities for the three months ended March 31, 2011 was $132.4 million or $0.74 per share compared to $186.6 million or $1.07 per share for the same period in 2010. The decrease was primarily due to lower oil and gas sales revenue resulting from decreased production as a result of our 2010 dispositions and lower natural gas prices.

Selected Canadian and U.S. Results

The following table provides a geographical analysis of key operating and financial results for the three months ended March 31, 2011 and 2010.

	Three months ended March 31, 2011			Three months ended March 31, 2010		
(CDN$ millions, except per share amounts)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Average Daily Production Volumes						
Natural gas (Mcf/day)	**217,373**	**34,107**	**251,480**	283,460	15,460	298,920
Crude oil (bbls/day)	**19,195**	**11,143**	**30,338**	23,936	7,038	30,974
Natural gas liquids (bbls/day)	**3,098**	**134**	**3,232**	3,925	–	3,925
Total Average Daily Production (BOE/day)	**58,522**	**16,961**	**75,483**	75,105	9,614	84,719
Pricing[(1)]						
Natural gas (per Mcf)	**$ 3.69**	**$ 5.28**	**$ 3.91**	$ 4.99	$ 7.07	$ 5.10
Crude oil (per bbl)	**75.24**	**81.89**	**77.69**	73.78	74.14	73.86
Natural gas liquids (per bbl)	**61.28**	**37.24**	**60.29**	57.47	–	57.47
Capital Expenditures						
Capital spending and office capital	**$ 92.2**	**$ 83.8**	**$ 176.0**	$ 56.2	$ 38.5	$ 94.7
Acquisitions	**12.2**	**36.0**	**48.2**	3.7	35.9	39.6
Dispositions	**(59.7)**	**–**	**(59.7)**	(1.5)	–	(1.5)
Revenues						
Oil and gas sales[(1)]	**$ 219.9**	**$ 98.8**	**$ 318.7**	$ 306.5	$ 56.8	$ 363.3
Royalties[(2)]	**(33.7)**	**(24.8)**	**(58.5)**	(52.0)	(13.4)	(65.4)
Commodity derivative instruments gain/(loss)	**(76.1)**	**–**	**(76.1)**	33.3	–	33.3
Expenses						
Operating	**$ 50.6**	**$ 6.5**	**$ 57.1**	$ 72.4	$ 3.5	$ 75.9
General and administrative	**22.3**	**3.4**	**25.7**	17.9	2.4	20.3
Depletion, depreciation and amortization	**78.8**	**21.1**	**99.9**	106.0	12.1	118.1
Impairment	**32.4**	**–**	**32.4**	297.6	–	297.6
Current income taxes expense/(recovery)	**–**	**0.8**	**0.8**	–	–	–

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

QUARTERLY FINANCIAL INFORMATION

Our 2011 and 2010 results below have been prepared in accordance with IFRS. The 2009 results as presented were prepared under previous Canadian GAAP. Crude oil and natural gas sales declined after the first quarter of 2010 as asset sales during 2010 reduced overall production levels putting downward pressure on oil and gas sales. During the remainder of 2010 and into 2011 reduced production was generally offset by rising crude oil prices.

The most significant changes to net income in 2010 were goodwill and PP&E impairment expenses. Net income was also affected by fluctuating commodity prices and risk management costs along with the fluctuating Canadian dollar.

QUARTERLY FINANCIAL INFORMATION ($ millions, except per share amounts)	**Oil and Gas Sales[(1)]**	**Net Income/(Loss)**	**Net Income/(Loss) Per Share**	
			Basic	**Diluted**
2011				
First quarter	**$ 318.7**	**$ 29.5**	**$ 0.17**	**$ 0.16**
2010				
Fourth Quarter	$ 313.2	$ 64.5	$ 0.37	$ 0.36
Third Quarter	305.5	(136.3)	(0.77)	(0.77)
Second Quarter	318.2	76.5	0.44	0.38
First quarter	363.3	(184.0)	(1.05)	(1.08)
Total	$ 1,300.2	$ (179.3)	$ (1.02)	$ (1.02)
2009 (Canadian GAAP)				
Fourth Quarter	$ 333.3	$ 2.7	$ 0.02	$ 0.02
Third Quarter	292.1	38.2	0.23	0.23
Second Quarter	306.2	(3.6)	(0.02)	(0.02)
First Quarter	301.2	51.8	0.31	0.31
Total	$ 1,232.8	$ 89.1	$ 0.53	$ 0.53

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

Liquidity and Capital Resources

Our $1.0 billion bank credit facility is an unsecured, covenant-based, three-year term agreement maturing June 30, 2013. Drawn fees under the facility range between 200 and 375 basis points over bankers' acceptance rates. We are currently paying 2% over bankers' acceptance rates which have recently been trading around 1% for a combined rate of approximately 3%. Standby fees on the undrawn portion of the facility are based on 25% of the drawn pricing. We have the ability to request an extension of the facility each year or repay the entire balance at the end of the term. The credit facility agreement, including all amendments and supplements, has been filed as a "Material Document" on the Company's SEDAR profile at www.sedar.com.

Total debt at March 31, 2011, including the current portion of $44.8 million, was $853.3 million, an increase of $120.9 million from $732.4 million at December 31, 2010. Total debt at March 31, 2011 was comprised of $366.2 million of bank indebtedness and $487.1 million of senior notes. The increase of $120.9 million in 2011 was mainly the result of our capital spending and dividends exceeding our funds flow and disposition proceeds during the first quarter of 2011. See Note 8 for further details.

During the first quarter of 2011, we swapped US$75.0 million of notional debt at an average foreign exchange rate of US/CDN $1.01. These foreign exchange swaps mature between June 2017 and June 2021 in conjunction with the principal repayments on our US$225 million senior notes. The exchange rate was originally US/CDN $1.13 when these U.S. dollar denominated notes were issued.

Our working capital at March 31, 2011, excluding cash and current deferred financial assets and credits, increased by $58.5 million compared to December 31, 2010. This change relates to lower capital spending during the first quarter compared to the fourth quarter of 2010, which decreased our payable balances. We expect to finance our negative working capital with our funds flow and bank indebtedness.

We have continued to maintain a conservative balance sheet as demonstrated below:

Financial Leverage and Coverage	March 31, 2011	December 31, 2010
Long-term debt to funds flow (12 month trailing)(1)	**1.2 x**	1.0 x
Funds flow to interest expense (12 month trailing)(2)	**15.5 x**	17.4 x
Long-term debt to long-term debt plus equity(1)	**20%**	18%

(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 March 31, 2011, we were in compliance with our debt covenants.

We expect to have adequate liquidity from funds flow and our bank credit facility to fund capital spending and working capital requirements for 2011. We expect our capital spending and dividends to exceed our funds flow in 2011 and 2012, and that our debt-to-funds flow ratio will increase during this time as we continue to invest in earlier stage growth assets where there is a longer lead time to production and funds flow. We will be actively monitoring our debt levels and may consider selling non-cash generating assets or selling part of our non-operated Marcellus interests to manage our debt and maintain our financial flexibility. We anticipate our debt-to-funds flow levels will decrease after 2012 as production and funds flow from our growth plays are realized.

Our payout ratio, which is calculated as dividends divided by funds flow, was 60% for the first quarter of 2011 compared to 48% for the same period in 2010. Our adjusted payout ratio, which is calculated as dividends plus capital spending and office capital divided by funds flow, was 169% for the quarter, compared to 96% for the first quarter of 2010. Our adjusted payout ratio increased during 2011 due to higher capital spending levels, which are not generating immediate production or funds flow, as well as lower funds flow overall. See "Non-GAAP Measures" above.

Dividend Policy

As a corporation we currently pay monthly dividends and we intend to continue to distribute a significant portion of our funds flow to our shareholders. During the first quarter of 2011 we paid $96.7 million ($0.54/share) in dividends to our shareholders. We will continue to assess dividend levels with respect to anticipated funds flow, debt levels, capital spending plans and capital market conditions and will adjust dividend levels as necessary. The payment of dividends, or the amount thereof, is not guaranteed.

Accumulated Deficit Reclassification

As part of the Plan of Arrangement our January 1, 2011 accumulated deficit balance of $2.3 billion was reclassified against share capital.

Shareholders' Capital

Effective January 1, 2011, pursuant to the Plan of Arrangement, unitholders of the Fund received one common share in Enerplus Corporation in exchange for each trust unit and 0.425 of a common share in Enerplus Corporation for each exchangeable partnership unit of Enerplus Exchangeable Limited Partnership ("EELP") held. Under IFRS, EELP units and trust unit rights were considered liabilities and were recorded on the consolidated balance sheet at fair value. Upon conversion to a corporation these liabilities were effectively converted into equity and the EELP liability was recorded to share capital and the trust unit rights liability was recorded to contributed surplus.

We had 179,278,000 shares outstanding at March 31, 2011 compared to 175,547,000 shares at March 31, 2010. We had 176,946,000 shares outstanding at December 31, 2010.

During the first quarter of 2011, 629,000 shares (2010 – 309,000) were issued pursuant to the Dividend Reinvestment Plan ("DRIP") and the stock option plan, resulting in $16.0 million (2010 – $6.7 million) of additional equity.

The weighted average basic number of shares outstanding for the three months ended March 31, 2011 was 178,832,000 (2010 – 174,488,000). At May 4, 2011 we had 179,524,000 shares outstanding.

2011 Guidance

There have been no changes to our 2011 guidance since year-end other than for non-cash G&A expenses due to IFRS. The summary below does not include any future potential acquisitions or divestments:

Summary of 2011 Expectations	Target	Comments
Average annual production	78,000 - 80,000 BOE/day	
Exit rate 2011 production	80,000 - 84,000 BOE/day	Assumes $650 million capital spending
2011 production mix	53% gas, 47% crude oil and liquids	
Average royalty rate	20%	Percentage of gross sales (net of transportation costs)
Operating costs	$9.20/BOE	
G&A costs	$3.45/BOE	Includes non-cash charges of $0.45/BOE
Average interest and financing costs	6%	Based on current fixed rate contracts and forward interest rates
Capital spending	$650 million	Within the context of current commodity prices
Marcellus carry commitment spending	$116 million	Will be reported as a property acquisition

INTERNAL CONTROLS AND PROCEDURES

There were no changes in our internal control over financial reporting during the period beginning on January 1, 2011 and ending on March 31, 2011 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

RECENT IFRS ACCOUNTING AND RELATED PRONOUNCEMENTS

March 31, 2011 is Enerplus' first reporting period under IFRS. Accounting standards effective for periods beginning on or after January 1, 2010 have been adopted as part of the transition to IFRS.

As of January 1, 2013, Enerplus will be required to adopt IFRS 9, "Financial Instruments", which is the result of the first phase of the International Accounting Standard Board's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. The adoption of this standard is not expected to have a material impact on our consolidated financial statements.

ADDITIONAL INFORMATION

Additional information relating to Enerplus Corporation and its predecessor Enerplus Resources Fund, including our 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 2011 average and exit oil, natural gas and natural gas liquids production volumes and the anticipated production mix; future oil and natural gas prices and our commodity risk management programs; operating, G&A and financing expenses; transfer of assets from the "exploration and evaluation" to the "property, plant and equipment" category for accounting purposes; capital spending levels and the allocation thereof among our assets and resource plays; the amount of future abandonment and reclamation costs and decommissioning liabilities; deferred income taxes, our tax pools and the time at which we may pay cash taxes; future debt and working capital levels and debt-to-funds-flow ratio; financial capacity, liquidity and capital resources to fund development capital spending and working capital requirements; the amount and timing of future cash dividends that we may pay to our shareholders; potential asset dispositions; average 2011 royalty rates; and our transition to IFRS and the impact of that change on our financial results and disclosure.*

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 and operating requirements as needed; 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; and certain other risks detailed from time to time in our public disclosure documents (including, without limitation, those risks and contingencies described under "Risk Factors and Risk Management" in our MD&A for the year ended December 31, 2010 and under "Risk Factors" in our Annual Information Form for the year ended December 31, 2010 dated March 11, 2011, which are available on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com and which form part of our Form 40-F filed with the SEC on March 11, 2011 available at www.sec.gov.

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

Condensed Consolidated Balance Sheets

(CDN$ thousands) unaudited	Note	March 31, 2011	December 31, 2010	January 1, 2010
Assets				
Current Assets				
Cash		**$ 3,616**	$ 8,374	$ 73,558
Accounts Receivable		**126,864**	125,928	142,009
Deferred financial assets	14	**2,624**	12,641	20,364
Other current		**50,600**	49,606	5,041
		183,704	196,549	240,972
Exploration and evaluation assets	4	**964,575**	1,545,378	580,184
Property, plant and equipment	5	**4,019,895**	3,440,568	4,420,339
Goodwill	6	**147,940**	151,345	476,998
Deferred financial assets	14	**3,822**	4,631	1,997
Other assets	7	**154,142**	150,710	88,324
Total Assets		**$ 5,474,078**	$ 5,489,181	$ 5,808,814
Liabilities				
Current liabilities				
Accounts payable		**$ 295,026**	$ 350,625	$ 257,519
Dividends payable		**32,280**	32,157	31,871
Current portion of long-term debt	8	**44,760**	45,845	36,631
Deferred financial credits	14	**127,755**	56,637	37,437
		499,821	485,264	363,458
Long-term debt	8	**808,541**	686,560	522,276
Deferred financial credits	14	**46,200**	46,942	54,788
Deferred tax liability		**429,422**	484,785	588,329
Decommissioning liability	9	**373,044**	392,709	385,885
		1,657,207	1,610,996	1,551,278
Exchangeable limited partnership units	13	**–**	44,387	55,812
Trust unit rights incentive plan	13	**–**	20,156	9,074
		–	64,543	64,886
Total Liabilities		**2,157,028**	2,160,803	1,979,622
Equity				
Shareholders' capital	13	**3,389,745**	5,639,380	5,576,763
Contributed surplus	13	**22,681**	3,795	3,795
Accumulated deficit		**(67,137)**	(2,314,775)	(1,751,366)
Accumulated other comprehensive income/(loss)		**(28,239)**	(22)	–
		3,317,050	3,328,378	3,829,192
Total Liabilities & Equity		**$ 5,474,078**	$ 5,489,181	$ 5,808,814

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Income and Comprehensive Income

Three months ended March 31 (CDN$ thousands) unaudited	Note	2011	2010
Revenues			
Oil and gas sales		**$ 324,002**	$ 369,640
Royalties		**(58,553)**	(65,367)
Commodity derivative instruments gain/(loss)	14	**(76,127)**	33,347
		189,322	337,620
Expenses			
Operating		**57,075**	75,927
General and administrative		**25,731**	20,316
Transportation		**5,274**	6,355
Depletion, depreciation, and amortization	5	**99,901**	118,132
Impairments	6	**32,394**	297,582
Foreign exchange	11	**1,662**	(10,409)
Finance expense	10	**14,007**	13,891
Asset disposition (gain)/loss		**(26,235)**	–
Other expense/(income)		**(407)**	257
		209,402	522,051
Income/(loss) before taxes		**(20,080)**	(184,431)
Current tax expense/(recovery)	12	**782**	–
Deferred income tax expense/(recovery)	12	**(50,411)**	(409)
Net Income/(loss)		**$ 29,549**	$ (184,022)
Other comprehensive income			
Change in fair value of available for sale financial instruments, net of tax	7	**$ 2,948**	$ 36,981
Change in cumulative translation adjustment		**(31,165)**	(26,634)
Other comprehensive income, net of tax		**(28,217)**	10,347
Total comprehensive income/(loss)		**$ 1,332**	$ (173,675)
Net income per share			
Basic		**$ 0.17**	$ (1.05)
Diluted		**$ 0.16**	$ (1.08)
Weighted average number of shares outstanding (thousands)	13		
Basic		**178,832**	174,488
Diluted		**179,452**	176,544

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Changes in Shareholders' Equity

Three months ended March 31 (CDN$ thousands) unaudited	2011	2010
Shareholders' Capital		
Balance, beginning of year	**$ 5,639,380**	$ 5,576,763
Reclassification of EELP units	**44,387**	–
Reclassification of accumulated deficit	**(2,314,775)**	–
Conversion of EELP units	**–**	21,011
Stock option plan – cash	**4,922**	800
Stock option plan – non cash	**4,753**	288
DRIP	**11,078**	5,932
Balance, end of period	**$ 3,389,745**	$ 5,604,794
Contributed Surplus		
Balance, beginning of year	**$ 3,795**	$ 3,795
Reclassification of trust unit rights liability	**20,156**	–
Stock option plan – exercised	**(4,753)**	–
Stock option plan – expensed	**3,483**	–
Balance, end of period	**$ 22,681**	$ 3,795
Accumulated deficit		
Balance, beginning of year	**$ (2,314,775)**	$ (1,751,366)
Reclassification to Shareholders' Capital	**2,314,775**	–
Net income/(loss)	**29,549**	(184,022)
Dividends on common shares	**(96,686)**	(95,712)
Balance, end of period	**$ (67,137)**	$ (2,031,100)
Accumulated other comprehensive income		
Balance, beginning of year	**$ (22)**	$ –
Change in fair value of available for sale financial instruments, net of tax	**2,948**	36,981
Cumulative translation adjustment	**(31,165)**	(26,634)
Balance, end of period	**$ (28,239)**	$ 10,347
Total equity	**$ 3,317,050**	$ 3,587,836

See accompanying notes to the Condensed Consolidated Financial Statements

Condensed Consolidated Statements of Cash Flows

Three months ended March 31 (CDN$ thousands) unaudited	2011	2010
Operating Activities		
Net income/(loss)	**$ 29,549**	$ (184,022)
Non-cash items add/(deduct):		
Depletion, depreciation and amortization	**99,901**	118,132
Impairments	**32,394**	297,582
Change in fair value of derivative instruments	**80,777**	(23,181)
Deferred income tax (recovery)	**(50,411)**	(409)
Foreign exchange (gain)/loss on U.S. dollar debt	**(11,934)**	(15,366)
Accretion expense	**3,415**	3,887
Stock based compensation	**3,483**	(676)
Change in fair value of exchangeable limited partnership units	**–**	2,514
Amortization of debt transaction costs	**285**	(180)
Asset disposition (gain)/loss	**(26,235)**	–
	161,224	198,281
Decommissioning liabilities settled	**(4,210)**	(4,291)
Decrease/(Increase) in non-cash operating working capital	**(24,611)**	(7,362)
Cash flow from operating activities	**132,403**	186,628
Financing Activities		
Issue of shares pursuant to stock option and dividend reinvestment plan	**16,000**	6,732
Dividends to shareholders	**(96,686)**	(95,712)
Increase in bank debt	**132,971**	–
Decrease/(Increase) in non-cash financing working capital	**123**	57
Cash flow from financing activities	**52,408**	(88,923)
Investing Activities		
Capital expenditures	**(176,055)**	(94,683)
Property and land acquisitions	**(48,218)**	(39,635)
Property dispositions	**59,693**	1,538
Purchase of marketable securities	**–**	(566)
Increase in non-cash investing working capital	**(25,265)**	(11,722)
Cash flow from investing activities	**(189,845)**	(145,068)
Effect of exchange rate changes on cash	**276**	(96)
Change in cash	**(4,758)**	(47,459)
Cash, beginning of year	**8,374**	73,558
Cash, end of period	**$ 3,616**	$ 26,099
Supplementary Cash Flow Information		
Cash income taxes (received)/ paid	**$ 123**	$ (8,281)
Cash interest paid	**$ 4,467**	$ 1,475

See accompanying notes to the Condensed Consolidated Financial Statements

Notes to Condensed Consolidated Financial Statements

For the quarter ended March 31, 2011, with comparative figures for 2010.
All amounts are stated in Canadian dollars unless otherwise specified.

1. REPORTING ENTITY

These interim condensed consolidated financial statements ("interim Consolidated Financial Statements") and notes present the results of Enerplus Corporation and its subsidiaries, as successor to Enerplus Resources Fund. On January 1, 2011, Enerplus Resources Fund (the "Fund") converted from an income trust into a corporate entity under a Plan of Arrangement pursuant to the *Business Corporations Act (Alberta)* (the "Plan of Arrangement") and continued as Enerplus Corporation ("Enerplus" or the "Company"). Immediately following the conversion, the directors and management of Enerplus remained the same as immediately prior to the conversion and the Company continued to carry on the same business and own the same assets as immediately prior to conversion.

Under the Plan of Arrangement, investors holding Trust Units received one common share of Enerplus Corporation in exchange for each Trust Unit of the Fund, and investors holding Class B exchangeable limited partnership units in Enerplus Exchangeable Limited Partnership ("EELP") received 0.425 of a common share in Enerplus Corporation for each EELP unit held. Pursuant to the Plan of Arrangement, all outstanding securities of the Fund and EELP were cancelled and the Fund and EELP were dissolved.

As Enerplus and the Fund were under common control, and there was no change in control as a result of the Plan of Arrangement, the information herein including the consolidated financial statements for periods prior to the effective date of the Plan of Arrangement reflect the financial position, results of operations and cash flows as if Enerplus had always carried on the business formerly carried on by the Fund.

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 consolidated financial statements were authorized for issue by the Board of Directors on May 12, 2011.

2. BASIS OF PREPARATION

Enerplus' annual audited Consolidated Financial Statements for the year ended December 31, 2011 will be issued under International Financial Reporting Standards ("IFRS"). These interim Consolidated Financial Statements present Enerplus' initial financial results of operations and financial position under IFRS as at and for the three months ended March 31, 2011, including the 2010 comparative periods. As a result, they have been prepared in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards" and with International Accounting Standard ("IAS") 34, "Interim Financial Reporting", as issued by the International Accounting Standards Board ("IASB"). These interim Consolidated Financial Statements do not include all the necessary annual disclosures in accordance with IFRS. Previously, the Company prepared its interim and annual Consolidated Financial Statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP").

The preparation of these interim Consolidated Financial Statements resulted in certain changes to the Company's accounting policies as compared to those disclosed in the annual audited Consolidated Financial Statements for the period ended December 31, 2010 issued under Canadian GAAP. A summary of the significant changes to the accounting policies is disclosed in Note 15 along with reconciliations presenting the impact of the transition to IFRS for the comparative periods as at January 1, 2010, as at and for the three months ended March 31, 2010 and as at and for the twelve months ended December 31, 2010.

(a) Basis of Measurement

The consolidated financial statements have been prepared on the historical cost basis except for the following items which are measured at fair value:

- cash;
- derivative financial instruments;
- available for sale financial instruments; and
- share-based payment transactions.

(b) Functional and Presentation Currency

These consolidated financial statements are presented in Canadian dollars, which is Enerplus' functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand unless otherwise indicated.

(c) Use of Estimates and Judgment

The preparation of financial statements requires management to use judgment, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results could differ from those estimated.

The amounts recorded for depletion and depreciation of the petroleum and natural gas properties and for decommissioning liabilities are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

IFRS requires that the Company's oil and gas assets be aggregated into cash-generating units, based on their ability to generate largely independent cash flows, which are used to assess the assets for impairment. The determination of the Company's cash-generating units is subject to management's judgment.

The decision to transfer assets from exploration and evaluation to property, plant and equipment is based on management's assessment of technical feasibility and commercial viability and this is subject to management's judgment.

The estimated fair value of derivative instruments resulting in financial assets and liabilities, by their very nature, are subject to measurement uncertainty.

Compensation costs recorded for the stock option plan are subject to estimation as they are calculated using the Black Scholes option pricing model which is based on significant assumptions such as volatility, dividend yield, expected term and forfeiture rate. Other compensation plans are performance based and are also subject to management's judgment as to whether or not certain performance criteria will be met.

The determination of the income tax provision and other tax issues can be complex and require management judgment. As such, income taxes are subject to measurement uncertainty. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations may result in an increase or decrease in the Company's provision for income taxes.

Additional detail concerning estimates and judgment has been provided in Note 3.

3. SIGNIFICANT ACCOUNTING POLICIES

The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

(a) Basis of Consolidation

These interim Consolidated Financial Statements include the accounts of Enerplus and its subsidiaries. Intercompany balances and transactions are eliminated on consolidation. Interests in jointly controlled assets are accounted for using the proportionate consolidation method, whereby Enerplus' proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

The acquisition method of accounting is used to account for acquisitions of companies and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets transferred, equity instruments issued and liabilities incurred or assumed at the acquisition date. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date.

(b) Revenue

Revenue associated with the sale of crude oil and natural gas is recognized when title passes from the Company to its customers and is measured at the fair value of the consideration received or receivable based on price, volumes delivered and contractual delivery points. Realized gains and losses from commodity price risk management activities are recognized in revenue when the contract is settled and unrealized gains and losses on commodity price risk management activities are recognized in revenue based on the changes in fair value of the contracts at the end of the respective reporting period.

(c) Exploration and Evaluation Assets ("E&E") and Property, Plant and Equipment ("PP&E")

(i) E&E Assets

Costs incurred prior to acquiring the legal right to explore an area are charged directly to net income.

Costs incurred after the legal right to explore is obtained but before technical feasibility and commercial viability of the area has been established are capitalized as E&E assets. These costs generally include unproved property acquisition costs, geological and geophysical costs, sampling and appraisals, drilling and completion costs, and directly attributable internal costs.

Once an area is determined to be technically feasible and commercially viable the accumulated costs are tested for impairment. The carrying value, net of any impairment, is then reclassified to PP&E as a Developed and Producing ("D&P") asset. If an area is determined not to be technically feasible and commercially viable, or the Company discontinues its exploration and evaluation activity, any unrecoverable costs are charged to net income.

(ii) PP&E

All costs directly associated with the development of crude oil and natural gas reserves are capitalized on an area-by-area basis if they extend or enhance the recoverable reserves of the underlying assets. These expenditures are referred to as D&P assets and include assets where technical feasibility and commercial viability has been determined. Costs in this category include proved property acquisitions, drilling and completion costs, gathering and infrastructure, capitalized decommissioning costs, directly attributable internal costs and transfers of exploration and evaluation assets. Repairs and maintenance and operational costs that do not extend or enhance the recoverable reserves are charged to net income in the period.

D&P assets are aggregated into cash generating units ("CGUs") for the purposes of impairment testing and depletion calculations. CGUs are groups of assets that generate independent cash inflows and are generally defined based on geographic areas, with consideration given to how the assets are managed.

Gains and losses on disposals of properties are determined by comparing the proceeds to the net carrying value of the property and are recognized in net income.

(d) Depletion and Depreciation

The net carrying value of D&P assets is depleted using the unit of production method, calculated as the ratio of production in the year compared to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Reserves and production are converted to equivalent units on the basis of 6mcf = 1 bbl, reflecting the approximate energy content. Proved plus probable reserves are generally estimated using independent reserve engineers and represent the estimated quantities of crude oil and natural gas which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years.

E&E assets are not depleted.

(e) Impairment

(i) E&E

E&E assets are tested for impairment when indicators of impairment exist or when technical feasibility and commercial viability are established and the assets are reclassified to PP&E. The impairment test compares the E&E assets' carrying value to recoverable amount plus any excess recoverable amounts on D&P assets on a country by country basis. E&E assets that are determined not to be technically feasible and commercially viable are charged to net income.

(ii) PP&E and Goodwill

D&P assets included in PP&E are reviewed for impairment at a CGU level when indicators of impairment exist. When indicators of impairment exist, the carrying value of each CGU, including goodwill, is compared to its recoverable amount which is defined as the higher of its fair value less cost to sell ("FVLCTS") or its value in use ("VIU"). FVLCTS is determined to be the amount for which the asset could be sold in an arm's length transaction. VIU is based upon the estimated before tax net present value of the Company's proved plus probable reserves, as prepared by independent reserve evaluators. These estimates of future net revenues are based on forecast prices and costs, and are stated prior to the provision of financing and general and administrative expenses and after the deduction of royalties and estimated future capital expenditures. Forecast prices reflect heating values, quality differentials and transportation costs specific to the Company's assets. Future net revenues are discounted using the Company's weighted average cost of capital.

Where the carrying value exceeds the recoverable amount an impairment loss exists and is charged to net income. Impairment losses are first recorded against goodwill within a CGU and the remainder is recorded against the D&P assets.

Reversals of impairments are recognized when events or circumstances that triggered the original impairment have changed. Impairments can only be reversed in future periods up to the carrying amount that would have been determined, net of depletion and depreciation, had no impairment losses been previously recognized. Goodwill impairments are not reversed in future periods.

(f) Foreign Currency

(i) Foreign currency transactions

Transactions in foreign currencies are generally translated to Canadian dollars at the average exchange rate for the period. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Foreign currency differences arising on translation are recognized in net income in the period in which they arise.

(ii) Foreign operations

Assets and liabilities of Enerplus' U.S. operations are translated into Canadian dollars at period end exchange rates while revenues and expenses are translated using average rates for the period. Gains and losses from the translation are deferred and included in the cumulative translation adjustment ("CTA") which is part of accumulated other comprehensive income ("AOCI").

(g) Financial Instruments

(i) Non-derivative financial instruments

Non-derivative financial instruments comprise cash, accounts receivable, accounts payable, dividends payable to shareholders and debt. Cash is classified as "fair value through profit or loss" and is carried at fair value. Accounts receivable are classified as "loans and receivables" and are carried at amortized cost less any allowance for impairment. Accounts payable, dividends payable to shareholders and debt are classified as "other financial liabilities" and are carried at amortized cost.

Enerplus has certain equity investments in entities involved in the oil and gas industry which are included in other assets on the Consolidated Balance Sheets. These investments are classified as "available-for-sale" and are carried at fair value with changes in fair value recorded in other comprehensive income. The fair value of investments that are publicly traded are determined by reference to quoted market bid prices at the close of business on the balance sheet date. For investments where there is no public market, fair value is determined using valuation techniques including using recent arm's length market transactions. When investments are ultimately sold any gains or losses are recognized in net income and any unrealized gains or losses previously recognized in other comprehensive income are reversed.

Enerplus capitalizes transaction costs on premiums and long-term debt. These costs are amortized using the effective interest method.

(ii) Derivative financial instruments

Enerplus enters into financial derivative contracts in order to manage its exposure to market risks from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Enerplus has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though it considers most of these contracts to be economic hedges. As a result, all financial derivative contracts are classified as "fair value through profit or loss" and are recorded at fair value on the Consolidated Balance Sheets with changes in fair value recorded in net income. The fair values of these derivative instruments are generally based on an estimate of the amounts that would be paid or received to settle these instruments at the balance sheet date.

Enerplus accounts for its physical delivery purchase and sales contracts as executory contracts as they were entered into and continue to be held for the purpose of receipt or delivery of products in accordance with its expected purchase, sale or usage requirements. As such, these contracts are not considered to be derivative financial instruments. Settlements on these physical contracts are recognized in net income over the term of the contracts as they occur.

(h) Goodwill

Enerplus recognizes goodwill relating to corporate acquisitions when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired companies. The portion of goodwill that relates to its U.S. operations fluctuates due to changes in foreign exchange rates. For the purposes of impairment testing, goodwill is allocated to the CGUs that benefited from the synergies of the respective business combinations and is tested for impairment in conjunction with the CGU. Goodwill is stated at cost less impairment and is not amortized. Goodwill is not deductible for income tax purposes.

(i) Assets Held for Sale

Non-current assets, or disposal groups consisting of assets and liabilities, are classified as held for sale if management intends to sell the assets, the sale is highly probable and the assets are available for immediate sale in their present condition.

Assets classified as held for sale are measured at the lower of the carrying amount and fair value less costs to sell. Any impairments are recognized in net income in the period measured. Non-current assets and disposal groups held for sale are presented in current assets and liabilities within the Consolidated Balance Sheets. Assets held for sale are not depreciated, depleted or amortized.

(j) Share Based Payments

Enerplus uses the Black Scholes option pricing model to calculate the grant date fair value of stock options granted under the Company's stock option plan. This amount is charged to earnings as general and administrative expenses over the vesting period of the options, with a corresponding increase in contributed surplus. When options are exercised, the proceeds, together with the amount recorded in contributed surplus, are recorded to shareholders' capital.

Enerplus recognizes a liability in respect of its cash settled Performance Share and Restricted Share incentive plans, based on their estimated fair value. The liability is re-measured at each reporting date and at settlement date with any changes in the fair value recorded as general and administrative expenses in net income.

(k) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by recognizing the present value of the estimated future cash flows, discounted using a risk-free rate.

(l) Decommissioning Liabilities

Enerplus' oil and gas operating activities give rise to dismantling, decommissioning and site remediation activities. Enerplus recognizes a liability for the estimated present value of the future decommissioning liabilities at each Balance Sheet date. The associated decommissioning cost is capitalized and amortized over the same period as the underlying asset. Changes in the estimated liability resulting from revisions to estimated timing, amount of cash flows, or changes in the discount rate are recognized as a change in the decommissioning liability and related capitalized decommissioning cost.

Amortization of capitalized decommissioning costs is included in depreciation, depletion and amortization in net income. Increases in decommissioning liabilities resulting from the passage of time are recorded as accretion which is included with finance expense in net income. Actual expenditures incurred are charged against the decommissioning liability.

(m) Income Tax

Income tax expense comprises current and deferred tax. Income tax expense is recognized in net income except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, along with any adjustment to tax payable in respect of previous years. Deferred tax is recognized using the balance sheet method, providing for temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(n) Net Income Per Share

Basic net income per common share is computed by dividing net income by the weighted average number of common shares outstanding during the period.

For the diluted net income per common share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income. The weighted average number of diluted shares is calculated in accordance with the treasury stock method which assumes that the proceeds received from the exercise of all stock options would be used to repurchase common shares at the average market price.

(o) New Pronouncements Adopted

March 31, 2011 is Enerplus' first reporting period under IFRS. Accounting standards effective for periods beginning on or after January 1, 2010 have been adopted as part of the transition to IFRS.

(p) Recent Pronouncements Issued

As of January 1, 2013, Enerplus will be required to adopt IFRS 9, "Financial Instruments", which is the result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

4. E&E ASSETS

($ thousands) **Carrying value**	**E&E assets**
As at January 1, 2010	$ 580,184
Capital spending and acquisitions	1,279,361
Dispositions	(260,697)
Impairment expense	(11,745)
Foreign currency translation adjustment	(41,725)
As at December 31, 2010	$ 1,545,378
Capital spending and acquisitions	142,782
Transfers to Property, Plant and Equipment	(704,953)
Foreign currency translation adjustment	(18,632)
As at March 31, 2011	**$ 964,575**

E&E assets consist of projects that management has not fully evaluated for technical feasibility and commercial viability.

As at March 31, 2011 the E&E asset balance is $964,575,000 (December 31, 2010 – $1,545,378,000), consisting primarily of Marcellus and Saskatchewan Bakken assets along with associated undeveloped lands. The transfer of approximately $704,953,000 from E&E assets to PP&E during the quarter was based on management's assessment of the technical feasibility and commercial viability of certain U.S. Fort Berthold assets ($693,338,000) and Marcellus assets ($11,615,000).

5. PP&E

($ thousands) **Carrying value before accumulated depletion and depreciation**	**D&P assets**	**Office and other**	**Total**
As at January 1, 2010	$ 4,402,061	$ 55,639	$ 4,457,700
Capital spending and acquisitions	269,346	4,004	273,350
Change in decommissioning costs	9,996	–	9,996
Dispositions	(399,354)	–	(399,354)
Foreign currency translation adjustment	(28,610)	(101)	(28,711)
As at December 31, 2010	$ 4,253,439	$ 59,542	$ 4,312,981
Capital spending and acquisitions	79,880	1,610	81,490
Transfers from Exploration and Evaluation	704,953		704,953
Change in decommissioning costs	(18,802)	–	(18,802)
Dispositions	(33,458)	–	(33,458)
Foreign currency translation adjustment	(24,179)	(54)	(24,233)
As at March 31, 2011	**$ 4,961,833**	**$ 61,098**	**$ 5,022,931**

Accumulated Depletion and Depreciation	**D&P assets**	**Office and other**	**Total**
As at January 1, 2010	$ –	$ 37,361	$ 37,361
Depletion, Depreciation and Amortization	453,387	7,770	461,157
Impairment	375,993	–	375,993
Foreign currency translation adjustment	(2,049)	(49)	(2,098)
As at December 31, 2010	$ 827,331	$ 45,082	$ 872,413
Depletion, Depreciation and Amortization	99,377	524	99,901
Impairment	32,394	–	32,394
Foreign currency translation adjustment	(1,672)	–	(1,672)
As at March 31, 2011	**$ 957,430**	**$ 45,606**	**$ 1,003,036**

Net carrying value	Developed and producing assets	Office and other	Total
As at January 1, 2010	$ 4,402,061	$ 18,278	$ 4,420,339
As at December 31, 2010	$ 3,426,108	$ 14,460	$ 3,440,568
As at March 31, 2011	$ 4,004,403	$ 15,492	$ 4,019,895

During the three months ended March 31, 2011, Enerplus disposed of assets for proceeds of $59,693,000, which resulted in a gain of $26,235,000. As at March 31, 2011 the Marcellus carry commitment balance remaining was US$117,116,000.

6. IMPAIRMENT EXPENSE

	Three months ended March 31	
($ thousands)	**2011**	**2010**
Goodwill	**$ –**	$ 260,744
D&P natural gas CGUs	**32,394**	36,838
Impairment expense	**$ 32,394**	$ 297,582

Upon adoption of IFRS, $130,440,000 related to historic goodwill was impaired and the remainder allocated to CGUs. For the year ended December 31, 2010 Enerplus recorded an impairment of $316,683,000 against the goodwill allocated to its Canadian CGUs. The remaining balance of goodwill at March 31, 2011 of $147,940,000 primarily pertains to a U.S. CGU and is exposed to fluctuations in foreign currency at each period end.

For the year ended December 31, 2010 Enerplus recorded a D&P impairment loss of $375,993,000 with respect to Canadian CGUs. The impairment losses were the result of lower forecasted natural gas prices. The recoverable amount was based on the assets value in use, estimated using the present value of the future net cash flows, discounted at 10%. Impairment losses on PP&E are included in impairment expense on the income statement.

7. OTHER ASSETS

Other assets consist of Enerplus' equity investments in entities involved in the oil and gas industry. For the three months ended March 31, 2011 the change in fair value of these investments represented a gain of $3,432,000 ($2,948,000 net of tax). For the three months ended March 31, 2010 Enerplus recorded an unrealized gain with respect to these same investments for $43,057,000 ($36,981,000 net of tax). There were no realized gains or losses on these investments for the three months ended March 31, 2011 and 2010.

8. DEBT

($ thousands)	Three months ended March 31, 2011	Year ended December 31, 2010	January 1, 2010
Current:			
Current portion of long-term debt	**$ 44,760**	$ 45,845	$ 36,631
	44,760	45,845	36,631
Long-term:			
Bank credit facility	**$ 366,240**	$ 234,713	$ –
Senior notes			
CDN$40 million (Issued June 18, 2009)	**40,000**	40,000	40,000
US$40 million (Issued June 18, 2009)	**38,872**	39,784	41,864
US$225 million (Issued June 18, 2009)	**218,655**	223,785	235,485
US$54 million (Issued October 1, 2003)*	**41,982**	42,967	56,516
US$175 million (Issued June 19, 2002)*	**102,792**	105,311	148,411
	808,541	686,560	522,276
Total debt	**$ 853,301**	$ 732,405	$ 558,907

* A portion of which has been classified as current.

During the first quarter of 2011 Enerplus entered into additional foreign currency swaps with respect to the Company's senior notes. Refer to Note 14 for additional information.

9. DECOMMISSIONING LIABILITY

($ thousands)	Three months ended March 31, 2011	Year ended December 31, 2010
Decommissioning liability, beginning of year	**$ 392,709**	$ 385,885
Changes in estimates	**(19,186)**	59,575
Property acquisition and development activity	**740**	6,894
Dispositions	**(424)**	(56,629)
Decommissioning liabilities settled	**(4,210)**	(17,240)
Accretion	**3,415**	14,224
Decommissioning liability, end of period	**$ 373,044**	$ 392,709

The majority of the $19,186,000 change in estimate for the three months ended March 31, 2011 was due to the change in the risk-free discount rate from 3.52% at December 31, 2010 to 3.75% at March 31, 2011.

10. FINANCE EXPENSE

($ thousands)	Three months ended March 31 2011	2010
Realized:		
Interest expense on bank debt and senior notes	**$ 11,900**	$ 9,216
Unrealized:		
Cross currency interest rate swap (gain)/loss	**(832)**	(633)
Interest rate swap (gain)/loss	**(761)**	(913)
Amortization of premiums and transaction costs	**285**	(180)
Accretion of decommissioning liability	**3,415**	3,887
Change in fair value of EELP units	**–**	2,514
Finance expense	**$ 14,007**	$ 13,891

11. FOREIGN EXCHANGE

($ thousands)	Three months ended March 31 2011	2010
Realized		
Foreign exchange (gain)/loss	**$ 7,259**	$ (2,436)
Unrealized		
Foreign exchange (gain)/loss on translation of U.S. dollar debt	**(11,934)**	(15,366)
Foreign exchange (gain)/loss on cross currency interest rate swap	**3,927**	6,014
Foreign exchange (gain)/loss on foreign exchange swaps	**2,410**	1,379
Foreign exchange (gain)/loss	**$ 1,662**	$ (10,409)

12. INCOME TAX EXPENSE

($ thousands)	Three months ended March 31 2011	2010
Current tax expense		
Canada	**$ –**	$ –
U.S.	**782**	–
Total current	**$ 782**	$ –
Deferred tax expense/(recovery)	**(50,411)**	(409)
Total income tax expense/(recovery)	**$ (49,629)**	$ (409)

Enerplus' previous income trust structure required certain temporary differences to be measured at higher deferred tax rates under IFRS. For the three months ended March 31, 2011 Enerplus recorded a $34,000,000 deferred tax recovery related to the reduction of this rate as a result of the conversion to a corporation on January 1, 2011.

13. SHAREHOLDERS' CAPITAL

Effective January 1, 2011, pursuant to the Plan of Arrangement, former unitholders of the Fund received one common share in Enerplus Corporation in exchange for each trust unit held and 0.425 of a common share in Enerplus Corporation for each exchangeable partnership unit of EELP held. On January 1, 2011, all outstanding securities of the Fund and EELP were cancelled. For comparative purposes, references to share capital and the stock option plan refer to trust units and the trust unit rights incentive plan ("TURIP") that were outstanding during 2010 and subsequently converted into share capital and stock options under the Plan of Arrangement.

Under IFRS, EELP units and trust unit rights were considered liabilities and were recorded on the consolidated balance sheet at their amortized fair value. Upon conversion to a corporation on January 1, 2011 these liabilities were effectively converted into equity and the EELP liability of $44,387,000 was recorded to share capital and the trust unit rights liability of $20,156,000 was recorded to contributed surplus. For more information refer to Note 13(c).

Pursuant to the Plan of Arrangement, shareholders' capital was reduced by the amount of the accumulated deficit of the Company on December 31, 2010 of $2,314,775,000.

(a) Share Capital

	Three months ended March 31, 2011		Year ended December 31, 2010	
Authorized: Unlimited number of common shares Issued: (thousands)	**Shares**	**Amount**	**Shares**	**Amount**
Balance, beginning of year	**176,946**	**$ 5,639,380**	174,349	$ 5,576,763
Corporate Conversion:				
Reclassification of EELP units (non-cash)	**1,703**	**44,387**	–	–
Reclassification of Accumulated Deficit (non-cash)	**–**	**(2,314,775)**	–	–
Issued for cash:				
Dividend reinvestment plan	**379**	**11,078**	1,212	28,781
Pursuant to stock option plan	**250**	**4,922**	375	6,638
Non-cash:				
Pursuant to stock option plan	**–**	**4,753**	–	3,014
Conversion of EELP units	**–**	**–**	1,010	24,184
Balance, end of period	**179,278**	**$ 3,389,745**	176,946	$ 5,639,380

(b) Dividends

During the three months ended March 31, 2011, Enerplus paid dividends of $0.18 per share per month for a total of $96,686,000 (three months ended March 31, 2010 – cash distributions of $0.18 per trust unit per month for a total of $95,712,000).

(c) Stock Option Plan

In connection with the Plan of Arrangement, Enerplus assumed all of the obligations of the Fund in respect of outstanding trust unit rights and no further grants will be made under the trust unit rights incentive plan. Outstanding trust unit rights were adjusted to entitle rights holders to purchase common shares of Enerplus in lieu of trust units on a one-for-one basis. No adjustments were made to exercise prices or vesting terms and the declining strike price mechanism will continue for these rights. Under IFRS outstanding trust unit rights were considered liabilities and were recorded on the consolidated balance sheet at fair value at each reporting period with any changes in fair value recorded to net income. On the January 1, 2011 conversion, outstanding rights ceased being liabilities and became equity based awards. As a result, the amortized fair value of $20,156,000 was reclassified from a liability to contributed surplus and their remaining unamortized fair value will be expensed over the vesting period of the rights. When the rights are exercised, the proceeds together with the amount recorded in contributed surplus, are recorded to shareholders' capital.

A new stock option plan for employees and officers of Enerplus was approved by shareholders in conjunction with the Plan of Arrangement. Options granted under the plan vest over a three year period and expire seven years after the grant date. The exercise price is equal to the market price at the time of the grant with no declining strike price mechanism. Enerplus uses the Black Scholes model to estimate the fair value of options granted under the plan. Previously, Enerplus used a binomial lattice model to estimate the fair value of rights granted under the trust unit rights incentive plan.

The following assumptions were used to arrive at the estimate of fair value for each of the respective reporting periods:

	March 31, 2011	December 31, 2010(1)	January 1, 2010(1)
Dividend yield	**7.11%**	7.12%	9.13%
Volatility	**35.00%**	44.23%	44.22%
Risk-free interest rate	**2.38%**	2.23%	2.48%
Forfeiture rate	**8.5%**	12.50%	12.40%
Expected life	**4.5 years**	3.4 years	3.9 years
Right's exercise price reduction	**$ –**	$ 0.74	$ 1.41

(1) Refers to the previous trust unit rights plan and calculated using a binomial lattice model.

The weighted average grant date fair value of options granted in 2011 was $4.38 (March 31, 2010 – $4.27). At March 31, 2011, 3,008,000 options were exercisable at a weighted average reduced exercise price of $35.80 with a weighted average remaining contractual term of 3.7 years, giving an aggregate intrinsic value of $11,503,000 (March 31, 2010 – $3,591,000).

For the three months ended March 31, 2011, 250,000 stock options were exercised at a weighted average reduced exercise price of $19.68, resulting in an intrinsic value of $2,859,000 (March 2010 – $288,000). The weighted average share price during the period was $31.32.

During the quarter Enerplus expensed $3,483,000 of stock based compensation expense, which is included in general and administrative expense. The unamortized fair value of $16,386,000 at March 31, 2011 will be recognized in net income over the remaining vesting period. Activity for the periods is as follows:

	Three months ended March 31, 2011		Year ended December 31, 2010	
	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	**5,457**	**$ 32.11**	5,250	$ 34.84
Granted	**2,014**	**30.40**	1,749	23.60
Exercised	**(250)**	**19.68**	(375)	17.50
Forfeited and expired	**(677)**	**44.45**	(1,167)	36.28
End of period	**6,544**	**$ 30.83**	5,457	$ 32.11
Options exercisable at the end of period	**3,008**	**$ 35.80**	2,565	$ 42.27

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

Contributed Surplus, as presented on the Consolidated Balance Sheets, is comprised of the following items:

($ thousands)	Three months ended March 31, 2011	Year ended December 31, 2010
Balance, beginning of year	**$ 3,795**	$ 3,795
Reclassification of trust unit rights liability	**20,156**	–
Stock option plan – exercised	**(4,753)**	–
Stock option plan – expensed	**3,483**	3,795
Balance, end of period	**$ 22,681**	$ 3,795

(d) Basic and Diluted Earnings Per Share

Basic per share calculations are calculated using the weighted average number of shares outstanding during the period. Diluted per share calculations include additional shares calculated using the treasury method and reflect the dilutive impact of the stock option plan. Diluted per share calculations for the three months ended March 31, 2010 also include the dilutive impact of outstanding EELP units.

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

	Three months ended March 31	
($ thousands)	**2011**	2010
Net income/(loss)	**$ 29,549**	$(184,022)
Finance expense on EELP units	**–**	(6,841)
Diluted income/(loss)	**$ 29,549**	$(190,863)
(units – thousands)		
Weighted average shares	**178,832**	174,488
Dilutive impact of options	**620**	232
Dilutive impact of EELP units	**–**	1,824
Diluted shares	**179,452**	176,544

(e) Long-term incentive plans

In conjunction with the Plan of Arrangement Enerplus assumed all of the obligations of the Fund under the Restricted Share Unit ("RSU") plan for employees and adopted a Performance Share Unit ("PSU") plan for management and executives. Values calculated for Enerplus' former Restricted Trust Unit ("RTU") plan will be based on common shares and dividends of Enerplus along with the applicable historic distributions of the Fund.

Under the RSU plan employees receive cash compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and vests one-third each year for three years. Upon vesting, plan participants receive a cash payment based on the value of the underlying notional shares plus accrued dividends over the vesting period.

Under the PSU plan executives and management receive cash compensation in relation to the value of a specified number of underlying notional shares. The number of notional shares awarded varies by individual and they vest at the end of three years. Upon vesting, the plan participant receives a cash payment based on the value of the underlying shares plus notional accrued dividends which are adjusted by a multiplier that ranges from 0.5 to 2.0 depending on the performance of Enerplus compared to its peers over the three year period.

For the three months ended March 31, 2011 the Company recorded cash compensation costs of $5,076,000 (March 31, 2010 – $3,676,000) with respect to its long-term incentive plans which was included in general and administrative expenses. At March 31, 2011 the long-term incentive plans had a liability balance of $12,613,000.

The following table summarizes the PSU and RSU activity for the three months ended March 31, 2011:

(thousands)	**Number of PSUs**	**Number of RSUs**
Balance, beginning of year	**–**	**999**
Granted	**181**	**437**
Vested	**–**	**(399)**
Forfeited	**–**	**(26)**
Balance, end of period	**181**	**1,011**

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

(a) Fair Value of Non-Derivative Financial Instruments

The fair values of cash, accounts receivable, accounts payable, dividends payable to shareholders and amounts owing under the bank credit facility approximate their carrying amounts at March 31, 2011 and December 31, 2010 due to their short-term maturities. At March 31, 2011 the combined fair values of Enerplus' senior notes was $556,333,000 and the carrying amount was $487,061,000 (December 31, 2010 – fair value of $559,049,000 and carrying value of $497,692,000). 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 liabilities on the Consolidated Balance Sheets result from recording these instruments at their fair value. As at March 31, 2011 $3,822,000 of unamortized transaction costs associated with the Company's credit facility were included in deferred financial assets on the Consolidated Balance Sheets.

The deferred financial liability relating to crude oil instruments is $104,861,000 at March 31, 2011 including deferred premiums of $5,012,000. At March 31, 2011 Enerplus did not have any outstanding natural gas derivative instruments.

The following table summarizes the fair value as at March 31, 2011 and change in fair value for the period ended March 31, 2011:

($ thousands)	Interest Rate Swaps	Cross Currency Interest Rate Swap	Foreign Exchange Swaps	Electricity Swaps	Commodity Derivative Instruments: Oil	Commodity Derivative Instruments: Gas	Total
Deferred financial assets/(liabilities), beginning of year	$ (3,640)	$ (61,095)	$ 385	$ (501)	$ (38,344)	$ 12,641	$ (90,554)
Change in fair value gain/(loss)	761(1)	(3,095)(2)	(2,410)(3)	3,125(4)	(66,517)(5)	(12,641)(5)	(80,777)
Deferred financial assets/(liabilities), end of period	**$ (2,879)**	**$ (64,190)**	**$ (2,025)**	**$ 2,624**	**$(104,861)**	**$ –**	**$(171,331)**
Statement of Financial Position classification:							
Current asset/(liabilities)	**$ (2,116)**	**$ (20,778)**	**$ –**	**$ 2,624**	**$(104,861)**	**$ –**	**$(125,131)**
Non-current asset/(liabilities)	**$ (763)**	**$ (43,412)**	**$ (2,025)**	**$ –**	**$ –**	**$ –**	**$ (46,200)**

(1) Recorded in finance expense.
(2) Recorded in foreign exchange expense (loss of $3,927) and finance expense (gain of $832).
(3) Recorded in foreign exchange expense.
(4) Recorded in operating expense.
(5) Recorded in commodity derivative instruments (see below).

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

($ thousands)	Three months ended March 31, 2011	2010
Change in fair value gain/(loss)	**$ (79,158)**	$ 29,394
Net realized cash gain/(loss)	**3,031**	3,953
Commodity derivative instruments gain/(loss)	**$ (76,127)**	$ 33,347

(c) Risk Management

Enerplus is exposed to commodity price fluctuations as part of its normal business operations. Risk management policies have been established by the Board of Directors to assist in managing a portion of these risks, with the goal of protecting earnings, funds flow and shareholder value. Enerplus manages a portion of these risks through a combination of financial derivative and physical delivery sales contracts.

(i) Commodity Price Instruments

The Company's policy is to enter into commodity contracts considered appropriate to a maximum of 80% of forecasted production volumes net of royalties. Enerplus' outstanding commodity derivative contracts at May 4, 2011 are listed below. Enerplus did not have any outstanding natural gas derivative contracts.

Crude Oil:

		WTI US$/bbl				
	Daily Volumes bbls/day	**Purchased Call**	**Sold Call**	**Purchased Put**	**Sold Put**	**Fixed Price and Swaps**
Term						
April 1, 2011 – Dec 31, 2011						
Purchased Call	1,500	$ 105.00	–	–	–	–
Purchased Call	1,000	$ 100.00	–	–	–	–
Purchased Call	500	$ 92.00	–	–	–	–
Swap	1,000	–	–	–	–	$ 87.65
Swap	500	–	–	–	–	$ 85.20
Swap	500	–	–	–	–	$ 88.95
Swap	500	–	–	–	–	$ 91.20
Swap	500	–	–	–	–	$ 91.88
Swap	500	–	–	–	–	$ 92.65
Swap	500	–	–	–	–	$ 94.80
Swap	1,000	–	–	–	–	$ 82.36
Swap	500	–	–	–	–	$ 85.50
Swap	500	–	–	–	–	$ 86.25
Swap	500	–	–	–	–	$ 80.30
Swap	1,500	–	–	–	–	$ 82.60
Swap	500	–	–	–	–	$ 81.69
Swap	500	–	–	–	–	$ 84.25
Swap	500	–	–	–	–	$ 85.40
Swap	500	–	–	–	–	$ 87.70
Swap	500	–	–	–	–	$ 86.73
Swap	500	–	–	–	–	$ 87.51
Swap	500	–	–	–	–	$ 89.20
Swap	500	–	–	–	–	$ 89.65
Swap	500	–	–	–	–	$ 87.20
Swap	500	–	–	–	–	$ 88.00
Swap	500	–	–	–	–	$ 89.00
Swap	500	–	–	–	–	$ 90.00
Swap	500	–	–	–	–	$ 91.25
Swap	500	–	–	–	–	$ 90.75
Swap	500	–	–	–	–	$ 92.40
Sold Put	1,500	–	–	–	$ 55.00	–
Sold Put	1,500	–	–	–	$ 58.00	–

	Daily Volumes bbls/day	WTI US$/bbl Purchased Call	Sold Call	Purchased Put	Sold Put	Fixed Price and Swaps
Jan 1, 2012 – Dec 31, 2012						
Swap	1,000	–	–	–	–	$ 90.40
Swap	1,000	–	–	–	–	$ 90.18
Swap	500	–	–	–	–	$ 91.84
Swap	500	–	–	–	–	$ 92.25
Swap(1)	500	–	–	–	–	$ 95.00
Swap(1)	500	–	–	–	–	$ 95.50
Swap(1)	500	–	–	–	–	$ 100.15
Swap(1)	500	–	–	–	–	$ 99.35
Swap(1)	500	–	–	–	–	$ 99.40
Swap(1)	500	–	–	–	–	$ 100.50
Swap(1)	500	–	–	–	–	$ 101.05
Swap(1)	500	–	–	–	–	$ 103.00
Swap(1)	1,000	–	–	–	–	$ 103.06
Swap(1)	500	–	–	–	–	$ 105.25
Swap(2)	500	–	–	–	–	$ 107.00
Three-way collar(1)	1,000	–	$ 133.00	$ 103.00	$ 65.00	–

(1) Financial contracts entered into during the first quarter of 2011.
(2) Financial contracts entered into subsequent to March 31, 2011.

Electricity:

Enerplus is subject to electricity price fluctuations and it manages this risk by entering into forward fixed rated electricity derivative contracts on a portion of its electricity requirements. The Company's outstanding electricity derivative contracts at May 4, 2011 are summarized below:

Term	Volumes MWh	Price CDN$/MWh
April 1, 2011 – December 31, 2011	3.0	$ 66.00
April 1, 2011 – December 31, 2011	3.0	$ 55.00
April 1, 2011 – December 31, 2011	3.0	$ 57.25
April 1, 2011 – December 31, 2011	3.0	$ 49.00
April 1, 2011 – December 31, 2011	2.0	$ 50.00
April 1, 2011 – December 31, 2011	2.0	$ 47.50
January 1, 2012 – December 31, 2012	3.0	$ 54.50
January 1, 2012 – December 31, 2012	2.0	$ 50.50
January 1, 2012 – December 31, 2012	5.0	$ 48.00

(ii) Foreign Exchange Swaps

During the first quarter of 2011 Enerplus entered into foreign exchange swaps on US$75,000,000 of notional debt at an average US/CDN foreign exchange rate of $1.01. These foreign exchange swaps mature between June 2017 and June 2021 in conjunction with the principal repayments on the US$225,000,000 senior notes.

15. TRANSITION TO IFRS

These interim Consolidated Financial Statements have been prepared in accordance with IFRS 1, "First-time Adoption of International Financial Reporting Standards" and with IAS 34, "Interim Financial Reporting", as issued by the IASB. Subsequent to the adoption of IFRS, Enerplus prepared its interim and annual Consolidated Financial Statements in accordance with Canadian GAAP.

IFRS 1 requires the presentation of comparative information as at the January 1, 2010 transition date along with subsequent comparative periods and, aside from the IFRS 1 exemptions available at the date of transition, retrospective application of IFRS accounting policies at the date of transition. In addition, IFRS requires the application of consistent accounting policies for all the periods presented.

To assist with the transition to IFRS the provisions of IFRS allow for certain mandatory and optional exemptions for first-time adopters to alleviate the retrospective application of all IFRS. Enerplus has applied the following exemptions:

Property, Plant and Equipment – This exemption allows companies that follow the Canadian GAAP full cost accounting guideline to allocate their historic net PP&E to CGUs on the date of transition. Enerplus has allocated PP&E into CGUs in Canada and the U.S., based on proved plus probable reserve values as at January 1, 2010.

Business Combinations – This is an optional exemption to the requirement to retroactively restate any past business combinations recorded under Canadian GAAP. Enerplus applied this exemption and therefore will not be retroactively restating past business combinations.

Cumulative Translation Adjustment ("CTA") – IFRS 1 provides an optional exemption to the requirement to retroactively restate CTA and instead allows entities to eliminate the CTA balance as of the date of transition. Enerplus applied this exemption and set CTA to zero at January 1, 2010 which resulted in an increase to the accumulated deficit of approximately $82 million.

Borrowing Costs – This exemption allows entities to be exempt from capitalizing interest on qualifying assets where active development commenced before January 1, 2010. Enerplus' Kirby oil sands asset, which was sold in October 2010, would be considered a "qualifying asset" on January 1, 2010. As a result of applying the exemption no interest was capitalized for Kirby.

The adoption of IFRS has had no impact on the Company's net increase or decrease in cash for any given period. As a result, although the changes made to the Consolidated Balance Sheets, Consolidated Income Statements and Consolidated Statements of Comprehensive Income resulted in reclassifications of various amounts on the Consolidated Statement of Cash Flows, no Consolidated Statement of Cash Flows has been included in this Note. The following financial statements, restated to comply with IFRS, have been provided:

- Consolidated Balance Sheets as at:
  - January 1, 2010;
  - March 31, 2010 and
  - December 31, 2010.
- Consolidated Income Statement for the periods ended:
  - March 31, 2010 and
  - December 31, 2010.
- Consolidated Statement of Comprehensive Income for the periods ended:
  - March 31, 2010 and
  - December 31, 2010.
- Consolidated Statement of Changes in Equity as at:
  - March 31, 2010 and
  - December 31, 2010.

Consolidated Balance Sheet

As at January 1, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments E&E	Impairment	Other Assets	Decommissioning Liability	EELP Units	TURIP	Foreign Exchange	Income Tax	IFRS
		(Note a)	(Note d)	(Note j)	(Note e)	(Note i)	(Note i)	(Note g)	(Note f)	
Assets										
Current Assets										
Cash	$ 74	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 74
Accounts receivable	142									142
Deferred financial assets	20									20
Deferred taxes – current	5								(5)	–
Other current	5									5
	246	–	–	–	–	–	–	–	(5)	241
Exploration and evaluation assets	–	580								580
Property, plant and equipment, net	5,000	(580)								4,420
Goodwill	607		(130)							477
Other assets	50			39						89
Deferred financial assets	2									2
	5,659	–	(130)	39	–	–	–	–	–	5,568
	$ 5,905	$ –	$ (130)	$ 39	$ –	$ –	$ –	$ –	$ (5)	$ 5,809
Liabilities										
Current Liabilities										
Accounts payable	257									257
Distributions payable to unitholders	32									32
Current portion of long term debt	37									37
Deferred financial credits	37									37
	363	–	–	–	–	–	–	–	–	363
Long term debt	522									522
Deferred financial credits	55									55
Decommissioning liability	230				155					385
Deferred income taxes	562			5	(42)				64	589
EELP units	–					56				56
TURIP	–						9			9
	1,369	–	–	5	113	56	9	–	64	1,616
Equity										
Shareholders' capital	5,689					(113)				5,576
Contributed surplus	26						(22)			4
Accumulated deficit	(1,460)		(130)	34	(113)	57	13	(82)	(69)	$ (1,750)
Accumulated other comprehensive income/(loss)	(82)							82		–
	4,173	–	(130)	34	(113)	(56)	(9)	–	(69)	3,830
	$ 5,905	$ –	$ (130)	$ 39	$ –	$ –	$ –	$ –	$ (5)	$ 5,809

Consolidated Balance Sheet

As at March 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	Pre-exploration	E&E	DD&A	Impairment	Other Assets	Decommissioning Liability	EELP Units	TURIP	Foreign Exchange	G&A	Income Tax	IFRS
		IFRS Adjustments											
		(Note a)	(Note a)	(Note b)	(Note d)	(Note j)	(Note e)	(Note i)	(Note i)	(Note g)	(Note h)	(Note f)	
Assets													
Current Assets													
Cash	$ 26	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 26
Accounts receivable	148												148
Deferred financial assets	56												56
Other current	6												6
	236		–	–	–	–	–	–	–	–	–	–	236
Exploration & evaluation assets	–		645								1		646
Property, plant & equipment, net	4,956	(1)	(645)	37	(37)						(2)		4,308
Goodwill	603				(391)								212
Other assets	50					82							132
Deferred financial assets	1												1
	5,610	(1)	–	37	(428)	82	–	–	–	–	(1)	–	5,299
	$ 5,846	$ (1)	$ –	$ 37	$ (428)	$ 82	$ –	$ –	$ –	$ –	$ (1)	$ –	$ 5,535
Liabilities													
Current Liabilities													
Accounts payable	248												248
Distributions payable	32												32
Current portion of long term debt	36												36
Deferred income taxes	2											(2)	–
Deferred financial credits	46												46
	364		–	–	–	–	–	–	–	–	–	(2)	362
Long-term debt	507												507
Deferred financial credits	58												58
Decommissioning liability	230						155						385
Deferred income taxes	549			10	(10)	11	(42)					71	589
EELP units	–							37					37
TURIP	–								9				9
	$ 1,344	$ –	$ –	$ 10	$ (10)	$ 11	$ 113	$ 37	$ 9	$ –	$ –	$ 71	$ 1,585
Equity													
Shareholders' capital	5,696							(92)					5,604
Contributed surplus	27								(23)				4
Accumulated deficit	(1,476)	(1)		27	(418)	34	(113)	55	14	(82)	(1)	(69)	$ (2,030)
Accumulated other comprehensive income/(loss)	(109)					37				82			10
	4,138	(1)	–	27	(418)	71	(113)	(37)	(9)	–	(1)	(69)	3,588
	$ 5,846	$ (1)	$ –	$ 37	$ (428)	$ 82	$ –	$ –	$ –	$ –	$ (1)	$ –	$ 5,535

Consolidated Balance Sheet

As at December 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	E&E	DD&A	Impairment	Asset Dispositions	Other Assets	Decommissioning Liability	EELP Units	TURIP	Foreign Exchange	G&A	Transaction Costs	Income Tax	IFRS
		(Note a)	(Note a)	(Note b)	(Note d)	(Note c)	(Note j)	(Note e)	(Note i)	(Note i)	(Note g)	(Note h)	(Note k)	(Note f)	
Assets															
Current Assets															
Cash	$ 8	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 8
Accounts receivable	126														126
Deferred financial assets	12														12
Deferred tax – current	11													(11)	–
Other current	50														50
	207	–	–	–	–	–	–	–	–	–	–	–	–	(11)	196
Exploration & evaluation assets	–	(1)	1,810		(11)	(261)						8			1,545
Property, plant & equipment, net	4,977	–	(1,810)	170	(378)	473		28				(19)			3,441
Goodwill	600				(447)	(1)									152
Deferred financial assets	–												4		4
Other assets	51						99								150
	5,628	(1)	–	170	(836)	211	99	28	–	–	–	(11)	4	–	5,292
	$ 5,835	$ (1)	$ –	$ 170	$ (836)	$ 211	$ 99	$ 28	$ –	$ –	$ –	$ (11)	$ 4	$ (11)	$ 5,488
Liabilities															
Current Liabilities															
Accounts payable	351														351
Distributions payable	32														32
Current portion of long-term debt	46														46
Deferred financial credits	56														56
	485	–	–	–	–	–	–	–	–	–	–	–	–	–	485
Long-term debt	686														686
Deferred financial credits	47														47
Decommissioning liability	209							183							392
Deferred income taxes	503			27	(101)	54	12	(42)				(3)	1	34	485
EELP units	–								44						44
TURIP	–									20					20
	$ 1,445	–	$ –	$ 27	$ (101)	$ 54	$ 12	$ 141	$ 44	$ 20	$ –	$ (3)	$ 1	$ 34	$ 1,674
Equity															
Shareholders' capital	5,728								(89)						5,639
Contributed surplus	29									(25)					4
Accumulated deficit	(1,717)	(1)		143	(735)	157	34	(113)	45	5	(82)	(8)	3	(45)	$ (2,314)
Accumulated other comprehensive income/(loss)	(135)						53				82				–
	3,905	(1)	–	143	(735)	157	87	(113)	(44)	(20)	–	(8)	3	(45)	3,329
	$ 5,835	$ (1)	$ –	$ 170	$ (836)	$ 211	$ 99	$ 28	$ –	$ –	$ –	$ (11)	$ 4	$ (11)	$ 5,488

Consolidated Income Statement

Three months ended March 31, 2010 Unaudited (CDN $ millions, except per unit amounts)	Previous GAAP	Pre-exploration	DD&A	Impairment	Decommissioning Liability	EELP Units	TURIP	G&A	IFRS
		IFRS Adjustments							
		(Note a)	(Note b)	(Note d)	(Note e)	(Note i)	(Note i)	(Note h)	
Oil and gas sales	$ 370	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 370
Royalties	(65)								(65)
Commodity derivative instruments	33								33
Revenues	$ 338								$ 338
Expenses									
Operating costs	76								76
General and administrative	20						(1)	1	20
Transportation	6								6
Finance expense	7				4	2			13
Foreign exchange (gain) loss, net	(10)								(10)
Impairment expense	–			298					298
Depreciation, depletion & amortization	159		(37)		(4)				118
Other (income)/expense	–	1							1
	258	1	(37)	298	–	2	(1)	1	522
Net income/(loss) before income tax	80	(1)	37	(298)	–	(2)	1	(1)	(184)
Current tax expense /(recovery)	–								–
Deferred income tax expense/(recovery)	–	–	10	(10)	–	–	–	–	–
Net income/(loss)	$ 80	$ (1)	$ 27	$ (288)	$ –	$ (2)	$ 1	$ (1)	$ (184)

Net Income/(Loss) per Share (Note m)

	Previous GAAP	IFRS
Basic	**$ 0.45**	**$ (1.05)**
Diluted	**$ 0.45**	**$ (1.08)**

Consolidated Statement of Comprehensive Income

Three months ended March 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	Pre-exploration	DD&A	Impairment	Other Assets	EELP Units	TURIP	G&A	IFRS
		IFRS Adjustments							
		(Note a)	(Note b)	(Note d)	(Note j)	(Note i)	(Note i)	(Note h)	
Net income/(loss)	$ 80	$ (1)	$ 27	$ (288)	$ –	$ (2)	$ 1	$ (1)	$ (184)
Other comprehensive income, net of tax									
Change in cumulative translation adjustment	(27)								(27)
Unrealized gain on marketable securities					37				37
Comprehensive income/(loss)	$ 53	$ (1)	$ 27	$ (288)	$ 37	$ (2)	$ 1	$ (1)	$ (174)

Consolidated Income Statement

Twelve months ended December 31, 2010 Unaudited (CDN $ millions, except per unit amounts)	Previous GAAP	IFRS Adjustments Pre-exploration	E&E	DD&A	Impairment	Asset Dispositions	Decommissioning Liability	EELP Units	TURIP	G&A	Transaction Costs	Income Tax	IFRS
		(Note a)	(Note a)	(Note b)	(Note d)	(Note c)	(Note e)	(Note i)	(Note i)	(Note h)	(Note k)	(Note f)	
Oil and Gas Sales	$ 1,327	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 1,327
Royalties	(223)												(223)
Commodity derivative instruments	24												24
Revenues	**$ 1,128**	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**	**$ –**	**$ 1,128**
Expenses													
Operating costs	290												290
General and administrative	79								8	11			98
Transportation	27												27
Finance expense	47						14	12			(4)		69
Foreign exchange (gain)/loss, net	(1)												(1)
Impairment expense	–				706								706
Depreciation, depletion and amortization	645			(170)			(14)						461
Other (income)/expense	(1)	1				(211)							(211)
	1,086	1	–	(170)	706	(211)	–	12	8	11	(4)	–	1,439
Net income/(loss) before income tax	**$ 42**	**$ (1)**	**$ –**	**$ 170**	**$ (706)**	**$ 211**	**$ –**	**$ (12)**	**$ (8)**	**$ (11)**	**$ 4**	**–**	**$ (311)**
Current tax expense/(recovery)	(30)												(30)
Deferred income tax expense/(recovery)	(55)	–	–	27	(101)	54				(3)	1	(24)	(101)
Net income/(loss)	**$ 127**	**$ (1)**	**$ –**	**$ 143**	**$ (605)**	**$ 157**	**$ –**	**$ (12)**	**$ (8)**	**$ (8)**	**$ 3**	**$ 24**	**$ (180)**

Net Income (Loss) per Share (Note m)

	Previous GAAP	IFRS
Basic	**$ 0.72**	**$ (1.02)**
Diluted	**$ 0.71**	**$ (1.02)**

Consolidated Statement of Comprehensive Income

Twelve months ended December 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	E&E	DD&A	Impairment	Asset Dispositions	Other Assets	EELP Units	TURIP	G&A	Transaction Costs	Income Tax	IFRS
		(Note a)	(Note a)	(Note b)	(Note d)	(Note c)	(Note j)	(Note i)	(Note i)	(Note h)	(Note k)	(Note f)	
Net income/(loss)	$ 127	(1)	–	143	(605)	157		(12)	(8)	(8)	3	24	$ (180)
Other comprehensive income, net of tax													
Change in cumulative translation adjustment	(53)												(53)
Unrealized gain on marketable securities							53						53
Comprehensive income/(loss)	$ 74	(1)	–	143	(605)	157	53	(12)	(8)	(8)	3	24	$ (180)

Consolidated Statement of Changes in Equity

As at March 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments Pre-exploration	DD&A	Impairment	Decommissioning Liability	EELP Units	TURIP	Other Assets	Foreign Exchange	G&A	Income Tax	IFRS
		(Note a)	(Note b)	(Note d)	(Note e)	(Note i)	(Note i)	(Note j)	(Note g)	(Note h)	(Note f)	
Common Shares												
Balance, beginning of year	$ 5,689	$ –	$ –	$ –	$ –	$ (113)	$ –	$ –	$ –	$ –	$ –	$ 5,576
Issued for cash:												
DRIP	6											6
Stock option plan	1											1
Equivalent EELPs	–					21						21
Balance, end of period	$ 5,696	$ –	$ –	$ –	$ –	$ (92)	$ –	$ –	$ –	$ –	$ –	$ 5,604
Contributed Surplus												
Balance, beginning of year	$ 26	$ –	$ –	$ –	$ –	$ –	$ (22)	$ –	$ –	$ –	$ –	$ 4
Stock option plan – expensed	1						(1)					–
Balance, end of period	$ 27	$ –	$ –	$ –	$ –	$ –	$ (23)	$ –	$ –	$ –	$ –	$ 4
Accumulated Deficit												
Accumulated income, beginning of year	$ 3,265	$ –	$ –	$ (130)	$ (113)	$ 57	$ 13	$ 34	$ (82)	$ –	$ (69)	$ 2,975
Net income/(loss)	80	(1)	27	(288)	–	(2)	1	–	–	(1)	–	(184)
	3,345	(1)	27	(418)	(113)	55	14	34	(82)	(1)	(69)	2,791
Accumulated dividends, beginning of year	(4,725)											(4,725)
Dividends	(96)											(96)
	(4,821)											(4,821)
Balance, end of period	$(1,476)	$ (1)	$ 27	$ (418)	$ (113)	$ 55	$ 14	$ 34	$ (82)	$ (1)	$ (69)	$(2,030)
Accumulated Other Comprehensive Income												
Balance, beginning of year	$ (82)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 82	$ –	$ –	$ –
Change in cumulative translation adjustment	(27)											(27)
Unrealized gain on marketable securities	–							37				37
Balance, end of period	$ (109)	$ –	$ –	$ –	$ –	$ –	$ –	$ 37	$ 82	$ –	$ –	$ 10
Total Equity	$ 4,138	$ (1)	$ 27	$ (418)	$ (113)	$ (37)	$ (9)	$ 71	$ –	$ (1)	$ (69)	$ 3,588

Consolidated Statement of Changes in Equity

Twelve months ended December 31, 2010 Unaudited (CDN $ millions)	Previous GAAP	IFRS Adjustments: Pre-exploration	DD&A	Impairment	Asset Dispositions	Decommis-sioning Liability	EELP Units	TURIP	Other Assets	Foreign Exchange	G&A	Income Tax	Transaction Costs	IFRS
		(Note a)	(Note b)	(Note d)	(Note c)	(Note e)	(Note i)	(Note i)	(Note j)	(Note g)	(Note h)	(Note f)	(Note k)	
Trust Units														
Balance, beginning of year	$ 5,689	$ –	$ –	$ –	$ –	$ –	$ (113)	$ –	$ –	$ –	$ –	$ –	$ –	$ 5,576
Issued for cash:														
DRIP	29													29
Stock option plan	7													7
Non cash:														
Stock option plan	2							1						3
Equivalent EELPs	–						24							24
Balance, end of year	$ 5,727	$ –	$ –	$ –	$ –	$ –	$ (89)	$ 1	$ –	$ –	$ –	$ –	$ –	$ 5,639
Contributed Surplus														
Balance, beginning of year	$ 26	$ –	$ –	$ –	$ –	$ –	$ –	$ (22)	$ –	$ –	$ –	$ –	$ –	$ 4
Stock option plan (non-cash) – exercised	(2)							1						(1)
Stock option plan (non-cash) – expensed	6							(5)						1
Balance, end of year	$ 30	$ –	$ –	$ –	$ –	$ –	$ –	$ (26)	$ –	$ –	$ –	$ –	$ –	$ 4
Accumulated Deficit														
Accumulated income, beginning of year	$ 3,265	$ –	$ –	$ (130)	$ –	$ (113)	$ 57	$ 13	$ 34	$ (82)	$ –	$ (69)	$ –	$ 2,975
Net income/(loss)	127	$ (1)	143	(605)	157	–	(12)	(8)	–	–	(8)	24	3	(180)
	3,392	(1)	143	(735)	157	(113)	45	5	34	(82)	(8)	(45)	3	2,795
Accumulated dividends, beginning of year	(4,725)													(4,725)
Dividends	(384)													(384)
	(5,109)													(5,109)
Balance, end of year	$ (1,717)	$ (1)	$ 143	$ (735)	$ 157	$ (113)	$ 45	$ 5	$ 34	$ (82)	$ (8)	$ (45)	$ 3	$ (2,314)
Accumulated Other Comprehensive Income														
Balance, beginning of year	$ (82)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 82	$ –	$ –	$ –	$ –
Change in cumulative translation adjustment	(53)													(53)
Unrealized gain on marketable securities	–								53					53
Balance, end of year	$ (135)	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ 53	$ 82	$ –	$ –	$ –	$ –
Total Equity	$ 3,905	$ (1)	$ 143	$ (735)	$ 157	$ (113)	$ (44)	$ (20)	$ 87	$ –	$ (8)	$ (45)	$ 3	$ 3,329

The following discussion explains the significant differences between Enerplus' Canadian GAAP accounting policies and those applied by Enerplus under IFRS. IFRS policies have been retrospectively and consistently applied except where the IFRS 1 mandatory and optional exemptions detailed above permitted an alternative treatment.

IFRS ADJUSTMENTS

a) Property, Plant and Equipment

Under IFRS capital costs are recorded using one of the following three categories:

i) Pre-Exploration Costs ("Pre-E&E")

Under Canadian GAAP costs incurred prior to having obtained the legal right to explore were capitalized and included in PP&E using the full cost method of accounting. Under IFRS such expenditures are expensed as incurred.

These costs were approximately $1.0 million for the periods ended March 31, 2010 and December 31, 2010.

ii) E&E Assets

Under Canadian GAAP E&E assets were capitalized using the full cost method of accounting and included in PP&E. Under IFRS E&E assets are early stage assets that management has not fully evaluated for technical feasibility and commercial viability. IFRS requires E&E assets to be separately recognized on the face of the balance sheet and these costs are not subject to depletion. Under IFRS these capitalized costs are transferred from E&E assets to PP&E assets once technical feasibility and commercial viability has been determined.

At January 1, 2010 approximately $580 million of assets were recognized on the Consolidated Balance Sheet as E&E assets. The balance is comprised primarily of Enerplus' Kirby oil sands asset, prior to its disposition on October 1, 2010, and undeveloped lands in Canada and the U.S. As at December 31, 2010 Enerplus' E&E assets were $1,545 million including approximately $1,242 million in the United States and approximately $303 million in Canada. No E&E assets were transferred to PP&E during 2010.

iii) D&P Assets

Under Canadian GAAP D&P assets were capitalized using the full cost method of accounting and included in PP&E. Under IFRS D&P assets are accounted for in smaller cost centers, or CGUs and continue to be recognized on the Consolidated Balance Sheet as part of PP&E.

Using the IFRS 1 exemption available to companies previously using the Canadian GAAP full cost accounting guideline, the cost of net PP&E was $4,420 million on the date of transition to IFRS. The historic net oil and gas PP&E values were allocated to CGUs based on the attributed value of proved plus probable reserves at December 31, 2009.

On transition to IFRS Enerplus allocated the consolidated goodwill balance which was generated from historic business combinations to the CGUs that benefited from the synergies of the combination.

b) Depletion, Depreciation and Amortization

At January 1, 2010 accumulated depletion was set to zero in conjunction with the IFRS 1 exemption that allowed companies to allocate their historic net oil and gas PP&E values to CGUs.

Under Canadian GAAP depletion was calculated on a unit of production basis using proved reserves on a country by country basis. Under IFRS Enerplus depletes D&P assets on a CGU basis using proved plus probable reserves. This change reduced DD&A by approximately $37 million and $170 million for the three and twelve months ended December 31, 2010, respectively.

c) Asset Dispositions

Under Canadian GAAP full cost accounting gains and losses were not recognized upon disposition of oil and gas assets unless such a disposition altered the rate of depletion by 20% or more. Under IFRS gains and losses are recognized based on the difference between the proceeds from disposition and the asset's net carrying value.

For the twelve months ended December 31, 2010 Enerplus recognized a $211 million gain on divesment activities compared to no gain under Canadian GAAP.

d) Impairment

E&E assets

Under Canadian GAAP E&E assets were tested for impairment by comparing their recoverable amount to the carrying value as part of the entire PP&E full cost pool. Under IFRS E&E assets are subject to an assessment for impairment where indicators of impairment exist. The E&E asset impairment test compares the carrying value to the sum of the assets' fair value plus any excess of the D&P assets' recoverable amount over their carrying value on a country by country basis.

Where an E&E asset is determined to be technically feasible and commercially viable, the accumulated costs are transferred to D&P assets. When an area is determined not be to technically feasible and commercially viable, the unrecoverable costs are charged to net income.

As at January 1, 2010 there was no impairment on Enerplus' E&E assets. For the period ending December 31, 2010 Enerplus recorded impairment of $11 million on its E&E. During the same period under Canadian GAAP there were no impairments recorded.

D&P assets

Under IFRS testing for D&P asset impairments is completed at a CGU level compared to a country by country basis utilizing the full cost accounting guideline under Canadian GAAP. When indicators of impairment exist, the carrying value of each CGU, including goodwill, is compared to its recoverable amount which is defined as the higher of its FVLCTS or VIU. Where the carrying value exceeds the recoverable amount an impairment loss exists. Impairment losses are first recorded against goodwill within a CGU and the remainder is recorded against the D&P assets.

As at January 1, 2010 no impairments were recorded on Enerplus' D&P assets. For the period ending March 31, 2010 an impairment of approximately $37 million was recognized. For the period ending December 31, 2010 D&P asset impairments of approximately $378 million were recognized. The impairments related to Enerplus' natural gas focused CGUs and were the result of lower forward natural gas prices.

Goodwill

Under Canadian GAAP goodwill was carried on a consolidated basis and was assessed for impairment when indicators or impairment existed, or at least annually.

On transition to IFRS Enerplus allocated the consolidated goodwill balance which was generated from historic business combinations to the CGUs that benefited from the synergies of the combination.

At the date of transition, January 1, 2010, Enerplus recognized a goodwill impairment of $130 million. For the quarter ended March 31, 2010 and year ended December 31, 2010, goodwill impairments of approximately $261 million and $317 million, respectively, were recognized as a result of lower forward natural gas prices.

Reversals of impairment

The reversal of impairment losses on PP&E was not permitted under Canadian GAAP. Under IFRS impairment losses previously recorded are reversed if the conditions giving rise to the impairment have reversed. There were no reversals of impairment during 2010.

Goodwill impairments are not reversed in future periods under IFRS, which is consistent with Canadian GAAP.

e) Decommissioning Liabilities

Under Canadian GAAP and IFRS the estimated fair value of the future cash outflows associated with abandoning, reclaiming and remediating PP&E assets are recorded on the balance sheet. Under Canadian GAAP the estimates of future cash outflows were discounted using a credit adjusted risk-free rate whereas under IFRS a risk-free rate is used. Additionally, accretion expense under IFRS is classified as a finance expense whereas under Canadian GAAP it was included within DD&A.

At January 1, 2010 an increase of approximately $155 million was recorded to the decommissioning liability. In accordance with the IFRS 1 exemption for full cost oil and gas companies the offset of $113 million, net of tax, was recorded to accumulated deficit. Subsequent remeasurement of the decommissioning liabiity is recorded through PP&E.

For the three months ended March 31, 2010 and twelve months ended December 31, 2010 approximately $4 million and $14 million respectively of accretion was reclassified from DD&A to finance expense under IFRS.

f) Deferred Income Tax

Prior to the conversion to a corporation, Enerplus' income trust structure resulted in a higher deferred tax rate which increased the deferred tax liability under IFRS by approximately $69 million at the date of transition. Approximately $34 million of this increase reversed on January 1, 2011 upon conversion to a corporation, with a corresponding credit to income.

IFRS also requires all deferred taxes to be classified as long-term.

g) Foreign Currency Translation

Upon adoption of IFRS Enerplus utilized an exemption that enabled the cumulative translation adjustment ("CTA") balance to be set to zero rather than having to retroactively restate the CTA. As at March 31, 2010 and December 31, 2010 CTA recognized in other comprehensive income under IFRS was approximately $27 million and $53 million respectively.

h) General and Administrative

For the three months ended March 31, 2010 and twelve months ended December 31, 2010 Enerplus reduced its capitalized G&A by approximately $1 million and $11 million respectively. This reduction is primarily a result of capitalizing fewer G&A expenses associated with acquisition and divestiture activities under IFRS compared to Canadian GAAP.

i) EELP Units and TURIP

Under Enerplus' former trust indenture outstanding trust units were redeemable at the option of the holder at 85% of the current trading price. Under Canadian GAAP Enerplus' trust units and EELP units were considered permanent equity and included within Shareholders' Capital. Under IFRS Enerplus' trust units are considered puttable financial instruments, however a specific exemption for trust units allows them to be classified as permanent equity. This exemption does not apply to instruments that are convertible into trust units such as the EELP units and trust unit rights. As a result, IFRS requires the EELP units and trust unit rights to be reported as liabilities at their fair value with changes in fair value recorded to income. As EELP units are converted to trust units by unitholders, the associated liability is recorded to unitholders' capital. As rights are exercised, the proceeds, together with the amount recorded as a trust unit rights liability, is recorded to unitholders' capital.

On January 1, 2010 Enerplus recorded a $56 million liability representing the redemption value of the outstanding EELP units along with a $113 million reduction to Shareholders' Capital and $57 million decrease to accumulated deficit to retroactively adjust for the impact of the EELP units.

A trust unit rights liability of $9 million was recorded on January 1, 2010, representing the TURIP fair value determined using a binomial lattice option pricing model on that date. In conjunction with the liability a reduction of $22 million was recognized in Shareholders' Capital with an offsetting credit of $13 million to accumulated deficit.

j) Other Assets

Under Canadian GAAP investments in non-publicly traded securities are carried at cost. Under IFRS all securities, publicly or privately held, must be carried at fair value and revalued at each reporting date.

As at January 1, 2010 Enerplus recorded an increase in other assets of approximately $39 million with the offset recorded to accumulated deficit.

For the three months ended March 31, 2010 and the twelve months ended December 31, 2010 Enerplus' increases in the fair value of investments were $43 million ($37 million net of tax) and $60 million ($53 million net of tax) respectively. These changes were recorded to other comprehensive income, net of tax.

k) Transaction Costs

During the second quarter 2010 Enerplus renewed its bank credit facility and incurred a $5 million extension fee that was expensed under Canadian GAAP.

Under IFRS these transaction costs are capitalized and amortized to finance expense over the term of the facility. For the year ended December 31, 2010 Enerplus recorded amortization costs of approximately $1 million.

l) Business Combinations

Acquisitions prior to January 1, 2010

As part of its transition to IFRS Enerplus elected to restate only those business combinations that occurred on or after January 1, 2010. In respect of acquisitions prior to January 1, 2010 goodwill represents the amount recognized under previous Canadian GAAP, however the goodwill generated from historic business combinations was allocated to the CGUs that benefited from the synergies of the combination.

Transaction costs, other than those associated with the issue of debt or equity securities, that Enerplus incurs in connection with a business combination are expensed as incurred.

m) Net Income Per Share

The following table summarizes the weighted average shares outstanding after re-classification of the EELP units and TURIP:

(millions)	**Three months ended March 31, 2010**	**Twelve months ended December 31, 2010**
Weighted average shares outstanding		
Basic	**174**	176
Diluted	**177**	178

BOARD OF DIRECTORS

Douglas R. Martin[(1)(2)]
President
Charles Avenue Capital Corp.
Calgary, Alberta

Edwin V. Dodge[(9)(12)]
Corporate Director
Vancouver, British Columbia

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

Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation
Calgary, Alberta

David O'Brien[(3)]
Corporate Director
Calgary, Alberta

Elliott Pew[(7)]
Corporate Director
Boerne, Texas

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

W. C. (Mike) Seth[(3)(8)]
President
Seth Consultants Ltd.
Calgary, Alberta

Donald T. West[(7)(11)]
Corporate Director
Calgary, Alberta

Harry B. Wheeler[(5)(9)]
Corporate Director
Calgary, Alberta

Clayton Woitas[(7)(11)]
President
Range Royalty Management Ltd.
Calgary, Alberta

Robert L. Zorich[(10)]
Managing Director
EnCap Investments L.P.
Houston, Texas

(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 Health, Safety, Regulatory & Environment Committee
(12) Chairman of the Health, Safety, Regulatory & Environment Committee

OFFICERS

ENERPLUS CORPORATION

Gordon J. Kerr
President & Chief Executive Officer

Ian C. Dundas
Executive Vice President & Chief Operating Officer

Ray J. Daniels
Senior Vice President, Canadian Operations

Eric G. Le Dain
Senior Vice President, Strategic Planning, Reserves, & Marketing

Robert J. Waters
Senior Vice President & Chief Financial Officer

Jo-Anne M. Caza
Vice President, Corporate & Investor Relations

Rodney D. Gray
Vice President, Finance

Robert A. Kehrig
Vice President, Resource Development

Jennifer F. Koury
Vice President, Corporate Services

David A. McCoy
Vice President, General Counsel & Corporate Secretary

Patrick "Scott" Walsh
Vice-President, Information Systems

Kenneth W. Young
Vice President, Land

Jodine J. Jenson Labrie
Controller, Finance

ENERPLUS RESOURCES (USA) CORPORATION

Dana W. Johnson
President

CORPORATE INFORMATION

Operating Companies Owned by Enerplus Corporation

Enerplus Partnership
Enerplus Resources (USA) Corporation

Legal Counsel
Blake, Cassels & Graydon LLP
Calgary, Alberta

Auditors
Deloitte & Touche LLP
Calgary, Alberta

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Calgary, Alberta
Toll free: 1.866.921.0978

U.S. Co-Transfer Agent
Computershare Trust Company, N.A.
Golden, Colorado

Independent Reserve Engineers
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

Haas Petroleum Engineering Services, Inc.
Dallas, Texas

Stock Exchange Listings and Trading Symbols
Toronto Stock Exchange: ERF
New York Stock Exchange: ERF

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ABBREVIATIONS

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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

AOCI accumulated other comprehensive income

API American Petroleum Institute

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

CBM coalbed methane, otherwise known as natural gas from coal – NGC

COGPE Canadian oil and gas property expense

CTA cumulative translation adjustment

D&P developed and producing

E&E exploration and evaluation

F&D Costs finding and development costs

FD&A Costs finding, development and acquisition costs

FDC future development capital

HH "Henry Hub" a reference to the physical storage and trading hub in Louisiana which is the delivery point for the NYMEX Natural Gas contract

IFRS International Financial Reporting Standards

Mbbls thousand barrels

MBOE thousand barrels of oil equivalent

Mcf thousand cubic feet

Mcfe thousand cubic feet equivalent

Mcf/day thousand cubic feet per day

Mcfe/day thousand cubic feet equivalent per day

MMbbl(s) million barrels

MMBOE million barrels of oil equivalent

MMBtu million British Thermal Units

MMBtu/day million British Thermal Units per day

MMcf million cubic feet

MMcf/day million cubic feet per day

MWh megawatt hour(s) of electricity

NGLs natural gas liquids

NI 51-101 National Instrument 51-101 Oil and Gas Activities adopted by the Canadian Securities regulatory authorities (pertaining to reserve reporting in Canada)

OCI other comprehensive income

P+P Reserves proved plus probable reserves

PDP Reserves proved developed producing reserves

RLI reserve life index

WI percentage working interest ownership

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

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