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NEWS RELEASE

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FOR IMMEDIATE RELEASE

Enerplus Delivers 9% Production Growth and 190% Reserve Replacement in 2012

This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review the "Cautionary Note Regarding Forward-Looking Information and Statements" at the conclusion of this news release. Readers are also referred to "Information Regarding Reserves, Resources and Operational Information", "Notice to U.S. Readers" and "Non-GAAP Measures" at the end of this news release for information regarding the presentation of the financial, reserves, contingent resources and operational information in this news release. A full copy of our 2012 Financial Statements and MD&A have been filed on our website at www.enerplus.com, under our profile on SEDAR at www.sedar.com and on the EDGAR website at www.sec.gov.

Calgary, Alberta - Enerplus Corporation ("Enerplus") (TSX: ERF) (NYSE: ERF) is pleased to announce fourth quarter 2012 results as well as 2012 year-end operating, financial and reserves results.

We delivered significant production and funds flow growth in 2012 ending the year with strong fourth quarter results. Our funds flow improved by 12% over 2011 due to a 9% increase in production and a higher weighting to crude oil largely due to the successful results of our drilling program at Fort Berthold in North Dakota. We also delivered another strong year in terms of organic reserve growth, replacing over 190% of our production in 2012 at attractive finding and development costs ("F&D costs") for the second year in a row. Our proved plus probable ("P+P") F&D costs including future development capital ("FDC") were $24.21 per BOE in 2012. In addition, we preserved our financial flexibility exiting 2012 with a debt-to-funds flow ratio of 1.7 times and are positioned to deliver on our corporate objectives in 2013.

4TH QUARTER 2012 HIGHLIGHTS

- As a result of our successful capital development program, production volumes in the fourth quarter increased by 5% over the third quarter of 2012 averaging 85,490 BOE per day. When compared to the fourth quarter of 2011, total production volumes grew by 11%.
- Crude oil production in the fourth quarter was 22% higher than in the fourth quarter of 2011.
- Marcellus volumes also increased significantly, up 40% from the third quarter as production volumes previously delayed were brought on-stream.
- As a result of higher production volumes, stronger natural gas prices and lower expenses, funds flow increased by almost 50% from the third quarter of 2012 to approximately $200 million ($1.01 per share) for the fourth quarter. As a result of this increase in funds flow, our adjusted payout ratio (capital spending plus dividends net of participation in the Stock Dividend Program ("SDP") improved significantly to 104%.
- Operating costs improved significantly during the quarter, down 25% to $9.24 per BOE compared to the third quarter of 2012. General and administrative ("G&A") costs continued to track under our guidance averaging $2.34 per BOE.

- We continued to focus our capital spending activities on crude oil assets during the fourth quarter. We invested $160 million in development capital, 70% of which was weighted to crude oil drilling 10.8 net wells with 16.5 net wells brought on-stream during the quarter.

- We continued to improve the focus and concentration of our portfolio during the quarter through the sale of non-core assets. In December, we sold non-core oil assets in Manitoba including approximately 1,600 BOE per day of production for approximately $218 million. In addition, in December we consolidated our ownership in Montana through the purchase of an additional 20% working interest in the Sleeping Giant Bakken oil project for $118 million, essentially replacing the volumes from the Manitoba sale. We realized net proceeds of $100 million on these transactions.

2012 SUMMARY

OPERATIONS

- As a result of our successful development program in 2012, Enerplus grew annual average production by 9% to 82,098 BOE per day, in line with our guidance of 82,000 BOE per day. Average crude oil production increased by 21% to 36,509 bbls per day in 2012 and when combined with natural gas liquids, represented 49% of our total corporate volumes during the year. This growth was achieved mainly due to our success in Fort Berthold as well as positive results from our drilling and enhanced oil recovery project ("EOR") in Medicine Hat, Alberta. U.S. natural gas production primarily from the Marcellus continued to grow throughout 2012, offsetting declines in our Canadian natural gas volumes. On average, our total natural gas production remained virtually unchanged at 252 MMcf per day during 2012.

- We also achieved exit production of approximately 85,800 BOE per day, within our guidance range of 85,000 BOE per day to 88,000 BOE per day. This is an increase of almost 5% over 2011 exit production rates.

- Our total capital spending in 2012 was in line with our guidance at approximately $853 million. Approximately 72% of our spending was directed to our crude oil plays with the majority invested at Fort Berthold and in our Canadian crude oil assets. Approximately 85% of our capital spending was spent on drilling and completions in 2012 with 75 net wells drilled across all of our assets and 79 net wells brought on-stream.

RESERVES/RESOURCES

- Total P+P company interest reserves grew by 7.4% to 345.8 MMBOE compared to 321.9 MMBOE at December 31, 2011.
- We added 57.3 MMBOE of P+P reserves as a result of our successful development program, replacing over 190% of production.
- P+P oil and liquids reserves grew by approximately 12% to 206 MMBOE and now represent 60% of our total P+P reserves, up from 57% at year-end 2011. Approximately 66% of the reserve additions were from crude oil and represented a 283% replacement of our 2012 oil production.
- P+P reserves at Fort Berthold increased by 53% from 2011 to 86.1 MMBOE. We replaced almost 800% of our production in 2012 through the addition of 34.2 MMBOE P+P reserves.
- Canadian oil reserves, which are largely comprised of crude oil waterflood properties, decreased by 8% to 91.6 MMbbls mainly due to the sale of 8.3 MMbbls of P+P reserves associated with our Manitoba assets. Through our successful development activities, we replaced 107% of Canadian oil production.
- We replaced 111% of our natural gas production in 2012 and grew our P+P natural gas reserves by approximately 2% to 837 Bcf. The majority of the increase is attributable to our Marcellus shale gas assets where we added 86 Bcf of P+P. Total Marcellus P+P reserves at year-end increased to 225 Bcf and represented 27% of our total P+P natural gas reserves, up from 19% in 2011.
- Our P+P reserve life index increased to 10.9 years at December 31, 2012, up from 9.8 years at December 31, 2011 as a result of the increase in reserves primarily associated with Fort Berthold and the Marcellus.

Finding and Development Costs

- Our P+P F&D cost including FDC improved to $24.21 per BOE in 2012 from $26.26 per BOE in 2011.
- Excluding future development capital, our P+P F&D costs were $14.88 per BOE.
- 60% of our reserve additions were attributable to Fort Berthold and were added at a cost of $25.38 per BOE including FDC. The recycle ratio associated with these additions was 2.0 times.
- Our P+P Finding, Development and Acquisition ("FD&A") cost including FDC was $22.92 per BOE, reflecting the positive impact of our acquisition and divestment activities.
- Excluding FDC, our P+P FD&A cost was $13.48 per BOE.

Contingent Resources

- In addition to booked reserves, an assessment of our portfolio has identified economic best estimate contingent resources of 364 MMBOE, representing over 100% of our booked P+P reserves. Our contingent resources are comprised of:
  - 33.5 MMBOE of contingent resources attributable to both the Bakken and Three Forks at Fort Berthold. We converted 31.2 MMBOE of previously assessed contingent resources to reserves for the year and added 15.6 MMBOE of new contingent resources primarily associated with the Three Forks formation.
  - 60.3 MMBOE of contingent resources attributable to improved oil recovery ("IOR") and EOR in our Canadian oil assets. We converted 7.1 MMBOE of previously assessed contingent resources to reserves and added 14.3 MMBOE of net new contingent resources associated with our EOR and IOR projects in our waterflood assets.
  - 1.3 Tcf of contingent resources in the Marcellus shale gas. This estimate has decreased from our contingent resource estimate of 2.3 Tcf one year ago due to a number of factors. Approximately 124 Bcf of contingent resources were reclassified as reserves during 2012. However, as a result of a decline in the gas price forecast and lower than expected performance on our operated acreage in Pennsylvania and West Virginia, the contingent resource estimate has been reduced in some areas and eliminated in others where the current economics do not support further development or lease extension of the acreage. We did see an increase in the contingent resource estimates assigned to our non-operated leases in northeast Pennsylvania due to improved performance.
  - 283 Bcfe of contingent resources associated with our Wilrich deep gas assets in Canada were identified as a result of our successful drilling activities in 2012.

FINANCIAL

- Despite the collapse in natural gas prices during 2012, funds flow for the year totaled $644 million ($3.29 per share), up 12% from 2011 due to higher oil production, improved netbacks as well as gains from our hedging program.
- We took a number of important steps in 2012 to maintain financial flexibility throughout this period of weak natural gas prices and widening crude oil differentials:
  - we raised $331 million in proceeds from an equity offering in early 2012;
  - we closed a private placement of long-term notes in May for proceeds of $405 million;
  - we reduced our monthly dividend from $0.18 per share to $0.09 per share in July;
  - we implemented the SDP to allow all of our shareholders the option to receive Enerplus shares instead of cash dividends;
  - we sold the majority of our equity interests, including our shares in Laricina Energy, for proceeds of $147 million; and
  - in aggregate, we generated proceeds of approximately $200 million on our property divestment activities, net of acquisitions.
- As a result, we ended 2012 in a strong financial position with a debt to trailing 12 month funds flow ratio of 1.7 times, virtually unchanged from 2011. We had approximately $740 million of unused capacity on our $1 billion credit facility at December 31, 2012.

- We paid $1.62 per share in dividends to our shareholders in 2012. Combining our capital spending with our dividends net of participation in the SDP and Dividend Reinvestment Plan ("DRIP"), our adjusted payout ratio improved to 174% for the year versus 212% in 2011. We expect our payout ratio to improve in 2013 as a result of a 20% reduction in our capital spending for the year and an improved outlook for natural gas prices.

- Our operating costs averaged $10.64 per BOE during 2012 and G&A costs averaged $2.61 per BOE, both in line with our guidance.

- We realized cash gains on our commodity hedging program of $18.4 million for the year.

- During 2012, we recorded accounting impairments of $418 million on our Developed and Producing (D&P) oil and gas assets due to a decline in commodity prices, primarily natural gas prices, and higher future development costs. We also recorded impairments of $114 million on our Exploration and Evaluation assets during the year due to expiring undeveloped land and unrecoverable costs on discontinued projects. These asset impairments resulted in a net loss of $156 million ($0.80 per share) for 2012. The impairments do not impact our funds flow or cash flow. Should natural gas prices improve, we expect the value of our D&P assets to increase, which would positively impact net income in future periods.

SELECTED FINANCIAL RESULTS	**Three months ended December 31,**		**Twelve months ended December 31,**	
	2012	2011	**2012**	2011
Financial (000's)				
Funds Flow	$199,678	$156,682	$643,911	$573,609
Cash and Stock Dividends	53,572	97,725	301,560	388,904
Net Income/(Loss)	(158,711)	(299,415)	(155,734)	109,437
Debt Outstanding - net of cash	1,064,365	901,465	1,064,365	901,465
Capital Spending	160,202	344,837	852,843	865,712
Property and Land Acquisitions	121,391	45,263	185,337	255,209
Property Dispositions	220,135	3,082	275,771	641,190
Asset Impairments	331,095	327,309	531,825	359,703
Asset Disposition gain/(loss)	59,440	(29)	131,166	302,053
Debt to Trailing 12 Month Funds Flow	1.7x	1.6X	1.7x	1.6X
Financial per Weighted Average Shares Outstanding				
Funds Flow	$1.01	$0.87	$3.29	$3.19
Net Income	(0.80)	(1.66)	(0.80)	0.61
Weighted Average Number of Shares Outstanding (000's)	198,256	180,845	195,633	179,889
Selected Financial Results per BOE[1]				
Oil & Gas Sales[2]	$45.86	$50.29	$44.56	$48.85
Royalties	(9.54)	(9.62)	(8.95)	(8.92)
Commodity Derivative Instruments	2.04	(1.54)	0.61	(1.21)
Operating Costs	(9.24)	(11.64)	(10.53)	(10.33)
General and Administrative	(2.34)	(2.53)	(2.61)	(2.46)
Equity Based Compensation	(0.03)	(0.52)	(0.18)	(0.53)
Interest and Other Expenses	(1.44)	(1.70)	(1.42)	(1.59)
Taxes	0.08	(0.68)	(0.05)	(2.95)
Funds Flow	$25.39	$22.06	$21.43	$20.86

SELECTED OPERATING RESULTS	**Three months ended December 31,**		**Twelve months ended December 31,**	
	2012	2011	**2012**	2011
Average Daily Production				
Crude oil (bbls/day)	38,597	31,715	36,509	30,181
NGLs (bbls/day)	3,576	3,256	3,627	3,306
Natural gas (Mcf/day)	259,904	253,500	251,773	251,068
Total (BOE/day)	85,490	77,221	82,098	75,332
% Crude Oil & Natural Gas Liquids	49%	45%	49%	44%

Average Selling Price[2]				
Crude oil (per bbl)	$ 76.75	$ 87.56	$ 78.19	$ 83.48
NGLs (per bbl)	47.31	68.32	53.01	64.99
Natural gas (per Mcf)	3.01	3.41	2.39	3.72
USD/CDN exchange rate	0.99	1.02	1.00	0.99
Net Wells drilled	11	36	75	107

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

Average Benchmark Pricing	Three months ended December 31,		Twelve months ended December 31,	
	2012	2011	**2012**	2011
WTI crude oil (US$/bbl)	**$88.18**	$94.06	$94.21	$95.12
WTI crude oil: CDN$ equivalent (CDN$/bbl)	**87.30**	95.94	94.21	94.18
AECO natural gas – monthly index (CDN$/Mcf)	**3.06**	3.47	2.40	3.68
AECO natural gas – daily index (CDN$/Mcf)	**3.22**	3.17	2.39	3.62
NYMEX natural gas – monthly NX3 index (US$/Mcf)	**3.36**	3.61	2.80	4.07
NYMEX natural gas – monthly NX3 index:			2.80	4.03
CDN$ equivalent (CDN$/Mcf)	**3.33**	3.68		
US/CDN exchange rate	**0.99**	1.02	1.00	0.99

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

SHARE TRADING INFORMATION

For the twelve months ended December 31, 2012	**CDN* – ERF** (CDN$)	**U.S.** - ERF** (US$)
High	$26.94	$26.54
Low	$11.53	$11.35
Close	$12.90	$12.96

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

2012 DIVIDENDS PER SHARE	**CDN$**	**US$**[1]
First quarter total	$0.54	$0.54
Second quarter total	$0.54	$0.53
Third quarter total	$0.27	$0.27
Fourth quarter total	$0.27	$0.27
Total	$1.62	$1.61

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

2012 PRODUCTION & CAPITAL SPENDING

Crude Oil & NGLs (BOE/day)	**Q4 2012 Average Production**	**2012 Annual Average Production**	**2012 Exit Production***	**2012 Capital Spending ($million)**
Canada	23,890	23,891	23,712	169
United States	18,283	16,245	18,630	444
Total Crude Oil & NGLs (BOE/day)	**42,173**	**40,136**	**42,342**	**$613**
Natural Gas (Mcf/day)				
Canada	188,628	198,356	181,070	86
United States	71,276	53,417	79,594	154
Total Natural Gas (Mcf/day)	**259,904**	**251,773**	**260,664**	**$240**
Company Total (BOE/day)	**85,490**	**82,098**	**85,786**	**$853**

***December month**

2012 DRILLING ACTIVITY

Crude Oil	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in *	Wells On-stream**	Dry & Abandoned Wells
Canada	26.4	1.0	27.4	1.4	31.3	0.1
United States	30.9	0.1	31.0	7.6	28.4	-
Total Crude Oil	**57.3**	**1.1**	**58.4**	**9.0**	**59.7**	**0.1**
Natural Gas						
Canada	4.2	1.0	5.2	1.1	5.6	-
United States	11.6	-	11.6	7.5	13.8	-
Total Natural Gas	**15.8**	**1.0**	**16.8**	**8.6**	**19.4**	**-**
Company Total	**73.2**	**2.1**	**75.2**	**17.6**	**79.2**	**0.1**

*Wells drilled during the year that are pending potential completion/tie-in or abandonment as at December 31, 2012.
** Total wells brought on-stream during the year regardless of when they were drilled.

ASSET ACTIVITY

U.S. Crude Oil

Our U.S. crude oil assets located within the Williston Basin represent approximately 40% of Enerplus' total crude oil and natural gas liquids production. Throughout 2012, we continued to focus the majority of our capital spending program in the Fort Berthold region in North Dakota. We also acquired an additional 20% working interest in the Sleeping Giant project in Montana, thereby growing our interests in both regions.

At Fort Berthold, we advanced our understanding of both the Bakken and Three Forks opportunities in the region and grew production by approximately 120% in 2012, exiting at 14,000 BOE per day. We drilled a total of 26 net operated wells, 19 of which were Bakken wells and seven of which were Three Forks wells. We also participated alongside our partners on 5.1 net non-operated wells.

We continue to evaluate optimal spacing and densities in this region. Based upon results to date, we believe that ultimate recoveries will vary depending upon a number of factors including the lateral length and number of frac stages, the number of wells drilled within a drilling spacing unit and whether the wells are producing from the Bakken or Three Forks formation. We anticipate expected ultimate recoveries ("EURs") will be lower for wells landed in the Three Forks formation and for the third and fourth wells drilled in a spacing unit. As a result, we continue to expect that EURs per long lateral well could range between 500 and 800 Mbbls of crude oil.

As a result of our drilling activities, we grew reserves by 53%, adding 34.2 MMBOE of P+P reserves at a cost of $25.38 per BOE including FDC. We have 86.1 MMBOE of P+P reserves booked as of December 31, 2012 and the Fort Berthold region now represents 25% of our corporate P+P reserves. In addition, our internal assessment of the best estimate of contingent resources, as audited by our independent reserve evaluators, is now 33.5 MMBOE at Fort Berthold. We converted 31.2 MMBOE of contingent resources to reserves during the year and added 2.0 MMBOE of Bakken and 13.6 MMBOE of Three Forks contingent resources to our estimate.

In 2013, we expect to reduce our capital spending by approximately 25% over 2012 levels and plan to run a two-rig program drilling between 20 – 25 net operated wells during the year. We expect to grow daily production by approximately 30%. Our focus is to improve our capital efficiencies in 2013. As we exited 2012, we have seen significant cost improvement in the region, particularly in completion costs. As a result of these reductions and an improvement in execution, we would expect our well costs to decrease by 10% – 15% in 2013.

U.S. Natural Gas

Our U.S. natural gas assets are principally comprised of our Marcellus shale gas interests in Pennsylvania and West Virginia. During 2012, our efforts were focused exclusively in the Marcellus and were largely driven by lease retention of core acreage on our non-operated properties in the northeast Pennsylvania region. As natural gas prices declined throughout the year, our partners slowed their activities which resulted in a 20% reduction in capital spending from our original guidance to $154 million. We participated in the drilling of 11.6 net wells with 13.8 net wells brought on-stream. We experienced delays in bringing wells on-stream in the latter half of the year due to pipeline and infrastructure constraints. Despite these delays, production from the Marcellus doubled in 2012 to average 41 MMcf/day. Also as a result of our drilling activities, we estimate that approximately two thirds of our core non-operated acreage is now held by production.

Subsequent to year-end, a number of additional wells were tied-in and production is currently over 65 MMcf per day. Based upon current NYMEX prices, our U.S. natural gas production receives an operating netback of approximately $2.15 per Mcf, roughly 25% higher than our average Canadian natural gas production. We expect our U.S. natural gas production to represent almost 35% of our corporate natural gas volumes in 2013.

As a result of our drilling activities, P+P reserves increased in the Marcellus by 46% to 225 Bcf at year-end. Approximately 124 Bcf of contingent resources associated with our non-operated leases were converted to P+P reserves at year-end. Marcellus shale gas now accounts for approximately 27% of our total P+P natural gas reserves. The best estimate of contingent resources associated with the Marcellus declined to 1.3 Tcf from 2.3 Tcf in 2011.

We expect to reduce our capital program in the Marcellus by over 50% in 2013. We plan to spend approximately $80 million essentially all of which will be invested with our non-operated partners. By year-end, we expect the majority of our core non-operated Marcellus acreage will be held by production.

Canadian Crude Oil

Our Canadian crude oil assets are comprised primarily of properties under waterflood and are a core holding in our portfolio due to their low decline, significant EOR potential and the free cash flow they generate. Our key focus areas in 2012 were the advancement of our EOR programs at Giltedge and Medicine Hat as well as optimization and waterflood development at Medicine Hat Glauc "C", Pembina Cardium and in the Ratcliffe trend of Saskatchewan. In aggregate, a total of $169 million was invested in drilling, facility upgrades and optimization activities. As a result of this investment, we grew production by 7% in 2012, to 23,891 BOE per day up from 22,303 BOE per day in 2011.

At Medicine Hat Glauc "C", we continue to see positive results from our horizontal drilling and polymer injection programs. Production volumes increased from 2,600 BOE per day at the end of 2011 to 4,500 BOE per day at the end of 2012. Given the positive results we are seeing from the polymer injection, we expect to be in a position to make a decision to expand the polymer EOR project by mid-2013. In total, 5.5 MMBOE of incremental P+P reserves were booked at year end, including the conversion of 2.1 MMBOE of contingent resources associated with our EOR project, with an attractive F&D cost of $14.25 per BOE.

We replaced 107% of Canadian crude oil and natural gas liquids production in 2012. Total Canadian proved plus probable crude oil reserves decreased by 8% to 91.6 MMbbls, primarily due to the sale of our Manitoba assets which included 8.3 MMbbls of P+P reserves, In addition, our internal estimate of contingent resources associated with a portion of these assets increased by 7% year-over-year to 60.3 MMBOE with the addition of 14.3 MMBOE of contingent resources.

Canadian Natural Gas

As a result of the weak outlook for natural gas prices, capital investment in our Canadian natural gas assets was limited to projects with associated natural gas liquids. Our activities included delineation of our undeveloped acreage in the Cardium and Duvernay and additional drilling in the Wilrich. No capital was allocated to our shallow natural gas assets. As a result of the reduced spending, Canadian natural gas production and reserves declined in 2012 by 9% and 12% respectively.

Enerplus drilled and completed two horizontal wells in the Wilrich formation in 2012. Based upon our drilling results in 2012, we added approximately 24 Bcfe of P+P reserves and have internally assessed 283 Bcfe of best estimate contingent resources associated with the play.

We drilled our first vertical delineation well in the Duvernay late in 2012. Core and fluid analysis has confirmed that we are in the liquids rich fairway and we plan to drill a number of vertical delineation wells in the latter half of 2013 in order to further increase our understanding of the play. We continue to pursue joint ventures in both the Duvernay and Montney areas given the scale of these opportunities and to provide additional near-term funding.

INDEPENDENT RESERVES EVALUATION

All reserves information, including our U.S. reserves, has been prepared in accordance with Canadian National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101") standards. Independent reserve evaluations have been conducted on approximately 88% of the total proved plus probable value (discounted at 10%) of our reserves at December 31, 2012. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 76% of our Canadian reserves and essentially 100% of the reserves associated with our western U.S. assets. They also reviewed the internal evaluation completed by Enerplus on the remaining 24% of our Canadian assets. Haas Petroleum Engineering Services Inc. ("Haas") evaluated 100% of our Marcellus shale gas reserves in the U.S.

See "Information Regarding Reserves, Resources and Operational Information" at the end of this news release for information regarding the presentation of company interest reserves and contingent resources.

Forecast Price Assumptions

The estimated reserve volumes and the net present values of future net revenues ("NPV") at December 31, 2012 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2013. These prices were applied to the reserves evaluated by McDaniel and Haas, along with those evaluated internally by Enerplus and reviewed by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below. These forecast price assumptions reflect a reduction in the prices of natural gas at AECO and Henry Hub and also a decrease in the prices for our portfolio of crude oil as compared to the price assumptions used to calculate our reserves and NPV at December 31, 2011.

McDaniel January 2013 Forecast Price Assumptions

	WTI Crude Oil US$/bbl	Light Crude Oil[(1)] Edmonton CDN$/bbl	Hardisty Heavy Oil 12° API CDN$/bbl	Henry Hub Gas Price US$/MMBtu	Natural Gas 30 day spot @ AECO CDN$/MMBtu	Exchange Rate US$/CDN$
2013	92.50	87.50	65.60	3.75	3.35	1.00
2014	92.50	90.50	67.90	4.30	3.85	1.00
2015	93.60	92.60	69.50	4.85	4.35	1.00
2016	95.50	94.50	70.90	5.25	4.70	1.00
2017	97.40	96.40	72.30	5.70	5.10	1.00
Thereafter	**	**	**	**	**	1.00

(1) Edmonton Light Sweet 40 degree API, 0.3% sulphur content crude.
** Escalation varies after 2017.

Reserves Summary

The following table sets out our company interest, gross and net reserve volumes at December 31, 2012 by production type and reserve category under McDaniel's forecast price scenarios. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit and reserves associated with a property. Company interest reserves consist of gross reserves, which are before the deduction of any royalties, plus Enerplus' royalty interests in reserves. It should be noted that tables may not add due to rounding.

Reserves Summary	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Company Interest							
Proved producing	65,300	27,328	92,627	7,383	368,806	73,644	173,752
Proved developed non-producing	2,041	198	2,239	133	9,149	25,489	8,145
Proved undeveloped	25,898	3,995	29,893	1,720	35,951	46,994	45,438
Total proved	93,238	31,521	124,759	9,236	413,906	146,127	227,335
Total probable	55,922	10,991	66,913	5,387	198,727	78,373	118,483
Proved plus Probable	**149,160**	**42,512**	**191,672**	**14,623**	**612,634**	**224,500**	**345,817**
Gross							
Proved producing	64,635	27,316	91,951	7,252	354,911	73,644	170,628
Proved developed non-producing	2,037	198	2,235	133	9,126	25,489	8,137

Proved undeveloped	25,893	3,995	29,889	1,700	34,002	46,994	45,087
Total proved	92,565	31,509	124,074	9,085	398,038	146,127	223,853
Total probable	55,732	10,988	66,720	5,327	192,663	78,373	117,220
Proved plus Probable	**148,297**	**42,496**	**190,793**	**14,412**	**590,702**	**224,500**	**341,072**
Net							
Proved producing	55,337	22,074	77,411	5,211	317,836	59,317	145,481
Proved developed non-producing	1,651	173	1,824	104	7,714	20,667	6,658
Proved undeveloped	21,096	3,031	24,127	1,346	31,179	38,088	37,018
Total proved	78,084	25,278	103,362	6,662	356,729	118,072	189,157
Total probable	45,563	8,507	54,070	4,079	170,977	63,170	97,173
Proved plus Probable	**123,647**	**33,784**	**157,432**	**10,741**	**527,705**	**181,241**	**286,330**

Future Development Capital

Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production. The aggregate of the exploration and development costs incurred in the most recent year and the change during the year in estimated future development costs generally reflect the total finding and development costs related to reserve additions for that year.

The significant increase in FDC reported at year-end 2012 is primarily related to the increase in the number of undeveloped drilling locations added in Fort Berthold and the Marcellus along with higher well cost assumptions on previously booked locations mainly in Fort Berthold. F&D and FD&A costs have been calculated both including and excluding FDC.

The following is a summary of the independent reserve evaluators' estimated FDC required to bring total proved and probable reserves on production:

Future Development Capital	**Proved Reserves**	**Proved Plus Probable Reserves**
($ millions)		
2013	420	487
2014	419	501
2015	153	401
2016	46	282
2017	15	37
Remainder	59	70
Total FDC Undiscounted	1,113	1,779
Total FDC Discounted at 10%	954	1,475

F&D and FD&A Costs

	2012		**2011**	
($ millions except for per BOE amounts)	**Excluding FDC**	**Including FDC**	**Excluding FDC**	**Including FDC**
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital expenditures	$ 852.8	$ 852.8	$ 829.8	$ 829.8
Net change in future development capital	-	$ 534.6	-	$ 435.9
Company interest reserve additions (MMBOE)	57.3	57.3	48.2	48.2
F&D costs ($/BOE)	**$ 14.88**	**$ 24.21**	**$ 17.22**	**$ 26.26**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions (1)	$ 726.4	$ 726.4	$ 370.2	$ 370.2
Net change in future development capital	-	$ 509.1	-	$ 402.7
Company interest reserve additions (MMBOE)	53.9	53.9	43.2	43.2
FD&A costs ($/BOE)	**$ 13.48**	**$ 22.92**	**$ 8.57**	**$ 17.89**

Proved Reserves				
Finding & Development Costs				
Capital expenditures	$ 852.8	$ 852.8	$ 829.8	$ 829.8
Net change in future development capital	-	$ 248.3	-	$ 230.7
Company interest reserve additions (MMBOE)	38.4	38.4	31.5	31.5
F&D costs ($/BOE)	**$ 22.21**	**$ 28.67**	**$ 26.34**	**$ 33.67**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions [1]	$ 726.4	$ 726.4	$ 370.2	$ 370.2
Net change in future development capital	-	$ 241.3	-	$ 213.0
Company interest reserve additions (MMBOE)	36.6	36.6	28.9	28.9
FD&A costs ($/BOE)	**$ 19.85**	**$ 26.44**	**$ 12.81**	**$ 20.18**

(1) Capital spending totaled $852.8, net acquisition capital totaled $126.4 million and is exclusive of $37 million associated with the Marcellus carry commitment as the full purchase price associated with the Marcellus acquisition was used in the calculation of F&D and FD&A costs in 2009.

Reserve Reconciliation

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a company interest basis, from December 31, 2011 to December 31, 2012:

Proved Reserves – Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2011	46,437	29,304	75,741	7,781	437,622	-	156,458
Acquisitions	1	-	1	-	1	-	1
Dispositions	(6,333)	-	(6,333)	-	(1,545)	-	(6,590)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	734	4,155	4,889	74	3,268	-	5,507
Economic factors	(108)	(5)	(113)	(228)	(19,597)	-	(3,607)
Technical revisions	(114)	1,253	1,139	448	14,008	-	3,921
Production	(4,371)	(3,186)	(7,557)	(1,187)	(72,599)	-	(20,844)
Proved Reserves at Dec. 31, 2012	**36,246**	**31,521**	**67,767**	**6,887**	**361,158**	**-**	**134,847**

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2011	40,923	-	40,923	1,434	39,265	92,682	64,349
Acquisitions	3,751	-	3,751	-	6,707	-	4,868
Dispositions	(51)	-	(51)	-	(48)	-	(59)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	12,837	-	12,837	727	4,854	65,464	25,284
Economic factors	-	-	-	-	-	-	-
Technical revisions	5,339	-	5,339	328	6,636	2,866	7,250
Production	(5,805)	-	(5,805)	(140)	(4,665)	(14,885)	(9,204)
Proved Reserves at Dec. 31, 2012	**56,993**	**-**	**56,993**	**2,349**	**52,748**	**146,127**	**92,488**

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Reserves at Dec. 31, 2011	87,360	29,304	116,664	9,215	476,887	92,682	220,807
Acquisitions	3,752	-	3,752	-	6,707	-	4,870
Dispositions	(6,384)	-	(6,384)	-	(1,593)	-	(6,650)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	13,571	4,155	17,726	801	8,123	65,464	30,791
Economic factors	(108)	(5)	(113)	(228)	(19,597)	-	(3,607)
Technical revisions	5,224	1,253	6,477	776	20,643	2,866	11,171
Production	(10,177)	(3,186)	(13,362)	(1,327)	(77,265)	(14,885)	(30,048)
Proved Reserves at Dec. 31, 2012	**93,238**	**31,521**	**124,759**	**9,236**	**413,906**	**146,127**	**227,335**

Probable Reserves – Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2011	13,554	10,090	23,644	2,955	167,346	-	54,491
Acquisitions	-	-	-	-	-	-	-
Dispositions	(1,991)	-	(1,991)	(14)	(2,650)	-	(2,447)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	472	1,277	1,749	202	21,582	-	5,548
Economic factors	(44)	(2)	(45)	(71)	(4,750)	-	(908)
Technical revisions	819	(374)	445	71	(10,001)	-	(1,151)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2012	**12,811**	**10,991**	**23,802**	**3,143**	**171,526**	**-**	**55,533**

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2011	30,853	-	30,853	1,456	25,017	60,861	46,621
Acquisitions	1,110	-	1,110	-	1,980	-	1,440
Dispositions	(488)	-	(488)	-	(382)	-	(552)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	19,067	-	19,067	1,103	7,349	58,504	31,145
Economic factors	-	-	-	(44)	(4,156)	(3,231)	(1,275)
Technical revisions	(7,431)	-	(7,431)	(272)	(2,608)	(37,761)	(14,431)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2012	**43,111**	**-**	**43,111**	**2,243**	**27,201**	**78,373**	**62,950**

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Probable Reserves at Dec. 31, 2011	44,407	10,090	54,497	4,411	192,363	60,861	101,112
Acquisitions	1,110	-	1,110	-	1,980	-	1,440
Dispositions	(2,480)	-	(2,480)	(14)	(3,032)	-	(2,999)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	19,539	1,277	20,815	1,305	28,931	58,504	36,692
Economic factors	(44)	(2)	(45)	(114)	(8,906)	(3,231)	(2,183)

Technical revisions	(6,611)	(374)	(6,985)	(201)	(12,609)	(37,761)	(15,581)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2012	**55,922**	**10,991**	**66,913**	**5,387**	**198,727**	**78,373**	**118,483**

Proved Plus Probable Reserves – Company Interest Volumes (Forecast Prices)

CANADA	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2011	59,991	39,394	99,385	10,736	604,968	-	210,949
Acquisitions	1	-	1	-	1	-	2
Dispositions	(8,324)	-	(8,324)	(14)	(4,195)	-	(9,037)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	1,206	5,431	6,637	276	24,850	-	11,055
Economic factors	(152)	(7)	(159)	(299)	(24,347)	-	(4,515)
Technical revisions	705	879	1,584	519	4,006	-	2,770
Production	(4,371)	(3,186)	(7,557)	(1,187)	(72,599)	-	(20,844)
Proved Plus Probable Reserves at Dec. 31, 2012	**49,056**	**42,512**	**91,568**	**10,031**	**532,684**	**-**	**190,380**

UNITED STATES	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2011	71,776	-	71,776	2,890	64,282	153,543	110,970
Acquisitions	4,861	-	4,861	-	8,687	-	6,309
Dispositions	(540)	-	(540)	-	(430)	-	(611)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	31,904	-	31,904	1,830	12,204	123,968	56,429
Economic factors	-	-	-	(44)	(4,156)	(3,231)	(1,275)
Technical revisions	(2,092)	-	(2,092)	56	4,028	(34,895)	(7,180)
Production	(5,805)	-	(5,805)	(140)	(4,665)	(14,885)	(9,204)
Proved Plus Probable Reserves at Dec. 31, 2012	**100,104**	**-**	**100,104**	**4,592**	**79,950**	**224,500**	**155,438**

TOTAL ENERPLUS	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Plus Probable Reserves at Dec. 31, 2011	131,767	39,394	171,161	13,626	669,250	153,543	321,919
Acquisitions	4,862	-	4,862	-	8,688	-	6,310
Dispositions	(8,864)	-	(8,864)	(14)	(4,625)	-	(9,648)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	33,110	5,431	38,541	2,106	37,054	123,968	67,484
Economic factors	(152)	(7)	(159)	(342)	(28,503)	(3,231)	(5,790)
Technical revisions	(1,387)	879	(508)	575	8,035	(34,895)	(4,410)
Production	(10,177)	(3,186)	(13,362)	(1,327)	(77,265)	(14,885)	(30,048)
Proved Plus Probable Reserves at Dec. 31, 2012	**149,160**	**42,512**	**191,672**	**14,623**	**612,634**	**224,500**	**345,817**

CONTINGENT RESOURCES

The following table provides a breakdown of the best estimate of contingent resources associated with a portion of Enerplus' assets. The evaluation of contingent resources associated with the Wilrich and our leases at Fort Berthold was conducted by Enerplus and audited by McDaniel. Haas evaluated 100% of our Marcellus shale gas assets in the U.S. and provided the estimate of contingent resources. The contingent resource assessments associated with a portion of our waterflood properties were completed internally by qualified reserve evaluators.

Contingent Resources	"Best Estimate" Contingent Resources	Contingent Resource Net Drilling Locations
Canada		
Crude oil – IOR/EOR on a portion of waterfloods (MMbbls)	60.3	158
Natural gas - Wilrich (Bcfe)	282.6	57
Total Canada (MMBOE)	**107.4**	**215**
United States		
Crude oil and NGLs – Fort Berthold (MMBOE)	33.5	50
Natural gas - Marcellus (Bcf)	1,336.4	184
Total United States (MMBOE)	**256.2**	**234**
Total Company (MMBOE)	**363.6**	**449**

NET PRESENT VALUE OF FUTURE PRODUCTION REVENUE

The following table provides an estimate of the net present value of Enerplus' future production revenue after deduction of royalties, estimated future capital and operating expenditures, and before and after income taxes. It should not be assumed that the present value of estimated future cash flows shown below is representative of the fair market value of the reserves. The after tax net present value of future production revenues reflects the tax burden on properties on a stand-alone basis and does not consider the business entity-level tax situation or any potential tax planning.

Despite a 7.4% increase in our P+P reserves at December 31, 2012, the estimated before tax NPV using a 10% discount was 11% lower than the NPV 10% at December 31, 2011. This is due primarily to a reduction in both the forecast prices of natural gas and crude oil, and wider crude oil differentials used by our independent reserve evaluators.

Net Present Value of Future Production Revenue – Forecast Prices and Costs

Reserves at December 31, 2012, ($ millions, discounted at)	**0%**	**5%**	**10%**	**15%**
Proved developed producing	5,006	3,565	2,801	2,333
Proved developed non-producing	159	116	90	71
Proved undeveloped	1,083	549	293	147
Total Proved	6,249	4,230	3,183	2,552
Probable	4,523	2,344	1,469	1,023
Total Proved Plus Probable Reserves (before tax)	10,772	6,574	4,652	3,575
Total Proved Plus Probable Reserves (after tax)	8,191	5,164	3,757	2,954

NET ASSET VALUE

Enerplus' estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before taxes, as estimated by our independent reserve engineers, McDaniel and Haas, at year-end plus the estimated value of our undeveloped acreage and other equity investments, less decommissioning liabilities, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserve engineers.

In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserve reports with no further acquisitions or incremental development, including development of contingent resources. At December 31, 2012, the estimate of contingent resources contained within our leases was 364 million

BOE. As we execute our capital programs, we expect to convert contingent resources to reserves which could result in a doubling of our booked proved plus probable reserves. The land values described in the Net Asset Value table below do not necessarily reflect the full value of the contingent resources associated with these lands.

Net Asset Value (Forecast Prices and Costs at December 31, 2012) ($ millions except share amounts, discounted at)	**0%**	**5%**	**10%**	**15%**
Total net present value of proved plus probable reserves (before tax)	$10,772	$6,574	$4,652	$3,575
Undeveloped acreage (2012 Year End) (1)	426	426	426	426
Decommissioning liability (2)	(345)	(178)	(54)	(24)
Long-term debt, including current portion (net of cash)	(1,064)	(1,064)	(1,064)	(1,064)
Net working capital including deferred financial assets and credits	(91)	(91)	(91)	(91)
Other equity investments (3)	12	12	12	12
Net Asset Value of Assets	**$9,710**	**$5,679**	**$3,881**	**$2,834**
Net Asset Value per Share (4)	**$48.87**	**$28.58**	**$19.53**	**$14.26**

(1) Acreage acquired since 2008 valued at acquisition cost. Balance of undeveloped acreage valued at $100/acre.
(2) Decommissioning liability does not equal the amount on the balance sheet ($599.7 million) as the balance sheet amount uses a 2.36% discount rate and a portion of the decommissioning liability costs are already reflected in the present value of reserves computed by the independent engineers.
(3) Other equity investment portfolio is valued at the estimated fair value.
(4) Based on 198,684,000 shares outstanding as at December 31, 2012.

2013 OUTLOOK

We plan to spend approximately $685 million on exploration and development projects in 2013, 20% lower than our capital spending in 2012. Approximately 85% of our capital is expected to be allocated to crude oil and liquids rich natural gas projects, with 75% targeted to crude oil specifically. We expect production to average between 82,000 BOE per day and 85,000 BOE per day with a 50% weighting to crude oil and liquids. This is an expected increase of 2% versus 2012 using the mid-point of this range. Exit production is expected to average between 84,000 BOE per day and 88,000 BOE per day. Given the timing of capital spending and expected downtime for winter weather conditions, we expect production volumes during the first quarter will be slightly lower than the fourth quarter of 2012.

Based upon our production expectations and forward commodity prices at February 7, 2013, we expect to grow funds flow by approximately 8% over 2012 levels. As a result of this growth and lower capital spending, our adjusted payout ratio is expected to decline significantly in 2013. We plan to continue to sell non-core assets in order to preserve our financial strength and also improve the focus of our operations. We expect to end the year with a year-end debt-to-funds flow ratio of less than 2.0 times.

In addition, with the majority of funds flow expected to be generated from crude oil, we have hedged a significant amount of our 2013 crude oil production in order to provide greater certainty with respect to funds flow for the year. We currently have 60% of our anticipated 2013 crude oil production net of royalties hedged at an average price of approximately US$100.00 per barrel. We also have downside protection on 28% of our anticipated natural gas production net after royalties through 2013.

We navigated a challenging economic environment in 2012 through active portfolio management and preservation of balance sheet strength. We delivered significant production and reserves growth in 2012 which has positioned us well for 2013. We have a large portfolio of future opportunities in crude oil, dry natural gas and liquids rich natural gas that we will seek to maximize the value of through both our capital spending programs as well as possible joint venture opportunities. Our growing component of U.S. based production also provides us exposure to alternative markets and is expected to help improve the profitability of our business. Given the results we have achieved in 2012, we believe we provide a compelling value proposition for investors seeking exposure to the North American energy market.

2013 Guidance	**2013E**
Capital expenditures ($millions)	$685
Annual average daily production (BOE/day)	82,000 – 85,000
Oil & liquids weighting	50%
Exit production (BOE/day)	84,000 – 88,000
Oil & liquids weighting	50%

Adjusted payout ratio*	125%
Debt/funds flow at year-end	<2.0x
Cash operating costs ($/BOE)	$10.70
Cash G&A costs ($/BOE)	$2.70
Cash equity based compensation expenses ($/BOE)	$0.45
Royalties	21%
Cash taxes (% of U.S. cash flow)	~3%
Interest expense	5%

*Adjusted payout ratio is defined as capital spending plus dividends net of proceeds from the SDP divided by funds flow.

Gordon J. Kerr, President and CEO, will host a conference call today, February 22, 2013 at 9:00 a.m. MT (11:00 a.m. ET) to discuss these results. Details of the conference call are as follows:

Live Conference Call

Date: Friday, February 22, 2013
Time: 9:00 am MT/11:00 am ET
Dial-In: 647-427-7450
888-231-8191 (toll free)
Audiocast: http://www.newswire.ca/en/webcast/detail/1107509/1206991

To ensure timely participation in the conference call, callers are encouraged to dial in 15 minutes prior to the start time to register for the event. A podcast of the conference call will also be available on our website for downloading following the event. A telephone replay will be available for 30 days following the conference call and can be accessed at the following numbers:

Dial-In: 416-849-0833
1-855-859-2056 (toll free)
Passcode: 96353152

For further information, please contact our Investor Relations Department at 1-800-319-6462 or email investorrelations@enerplus.com.

INFORMATION REGARDING RESERVES, RESOURCES AND OPERATIONAL INFORMATION

Currency

All amounts in this news release are stated in Canadian dollars unless otherwise specified.

Barrels of Oil Equivalent and Cubic Feet of Gas Equivalent

This news release also contains references to "BOE" (barrels of oil equivalent), "Mcfe" (thousand cubic feet of gas equivalent), "Bcfe" (billion cubic feet of gas equivalent) and "Tcfe" (trillion cubic feet of gas equivalent). Enerplus has adopted the standard of six thousand cubic feet of gas to one barrel of oil (6 Mcf: 1 bbl) when converting natural gas to BOEs, and one barrel of oil to six thousand cubic feet of gas (1 bbl: 6 Mcf) when converting oil to Mcfes, Bcfes and Tcfes. BOEs, Mcfes, Bcfes and Tcfes may be misleading, particularly if used in isolation. The foregoing conversion ratios are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of oil as compared to natural gas is significantly different from the energy equivalent of 6:1, utilizing a conversion on a 6:1 basis may be misleading. "MBOE" and "MMBOE" mean "thousand barrels of oil equivalent" and "million barrels of oil equivalent", respectively.

Presentation of Production and Reserves Information

All production volumes and revenues presented herein are reported on a "company interest" basis, before deduction of Crown and other royalties, plus Enerplus' royalty interest. Unless otherwise specified, all reserves volumes in this news release (and all information derived therefrom) are based on "company interest reserves" using forecast prices and costs. "Company interest reserves" consist of "gross reserves" (as defined in NI 51-101), being Enerplus' working *interest before deduction of any royalties), plus Enerplus' royalty interests in reserves. "Company interest reserves" are not a measure defined in NI 51-101 and do not have a standardized meaning under NI 51-101. Accordingly, our company interest reserves may not be comparable to reserves presented or disclosed by other issuers. Our oil and gas reserves statement for the year ended December 31, 2012, which will include complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101, will be contained within our Annual Information Form for the year ended December 31, 2012 ("**our AIF**") which will be available in late February 2013 on our website at www.enerplus.com and under our SEDAR profile at www.sedar.com. Additionally, our AIF will form part of our Form 40-F that will be filed with the U.S. Securities and Exchange Commission and will available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements filed on SEDAR and EDGAR concurrently with this news release for more complete disclosure on our operations.*

Contingent Resource Estimates

*This news release contains estimates of "contingent resources". "Contingent resources" are not, and should not be confused with, oil and gas reserves. "Contingent resources" are defined in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") as "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as ultimate recovery rates, economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "contingent resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Enerplus expects to develop these contingent resources in the coming years however it is too early in their development for these resources to be classified as reserves at this time. All of our contingent resource estimates are economic using established technologies and under current commodity price assumptions used by our independent reserve evaluators. There is no certainty that we will produce any portion of the volumes currently classified as "contingent resources". The "contingent resource" estimates contained herein are presented as the "best estimate" of the quantity that will actually be recovered, effective as of December 31, 2012. A "best estimate" of contingent resources means that it is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate, and if probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.*

For additional information regarding the primary contingencies which currently prevent the classification of our disclosed "contingent resources" associated with our Marcellus shale gas properties, our Fort Berthold properties, our Wilrich natural gas properties and a portion of our Canadian crude oil properties as reserves and the positive and negative factors relevant to the "contingent resource" estimates, see our AIF for the year ended December 31, 2012 (and corresponding Form 40-F) dated February 22, 2013, a copy of which is available under our SEDAR profile at www.sedar.com and a copy of the Form 40-F which is available under our EDGAR profile at www.sec.gov.

F&D and FD&A Costs

F&D costs presented in this news release are calculated (i) in the case of F&D costs for proved reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves in the year, and (ii) in the case of F&D costs for proved plus probable reserves, by dividing the sum of exploration and development costs incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding and development costs related to its reserves additions for that year.

FD&A costs presented in this news release are calculated (i) in the case of FD&A costs for proved reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved reserves including net acquisitions in the year, and (ii) in the case of FD&A costs for proved plus probable reserves, by dividing the sum of exploration and development costs and the cost of net acquisitions incurred in the year plus the change in estimated future development costs in the year, by the additions to proved plus probable reserves including net acquisitions in the year. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally reflect total finding, development and acquisition costs related to its reserves additions for that year.

See "Non-GAAP Measures" below.

NOTICE TO U.S. READERS

*The oil and natural gas reserves information contained in this news release has generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. Reserves categories such as "proved reserves" and "probable reserves" may be defined differently under Canadian requirements than the definitions contained in the United States Securities and Exchange Commission (the "**SEC**") rules. In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross (or, as noted above, "company interest") volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the United States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. Canadian disclosure requirements require that forecasted commodity prices be used for reserves evaluations, while the SEC mandates the use of an average of first day of the month price for the 12 months prior to the end of the reporting period. Additionally, the SEC prohibits disclosure of oil and gas resources, whereas Canadian issuers may disclose oil and gas resources. Resources are different than, and should not be construed as reserves. For a description of the definition of, and the risks and uncertainties surrounding the disclosure of, contingent resources, see “Information Regarding Reserves, Resources and Operational Information” above.*

FORWARD-LOOKING INFORMATION AND STATEMENTS

*This news release contains certain forward-looking information and statements ("**forward-looking information**") within the meaning of applicable securities laws. 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 news release contains forward-looking information pertaining to the following: Enerplus' asset portfolio; future capital and development expenditures and the allocation thereof among our resource plays and assets; future development and drilling locations, plans and costs; the performance of and future results from Enerplus' assets and operations, including anticipated production levels, expected ultimate recoveries and decline rates; future growth prospects, acquisitions and dispositions; the volumes and estimated value of Enerplus' oil and gas reserves and contingent resource volumes and future commodity price and foreign exchange rate assumptions related thereto; the life of Enerplus' reserves; the volume and product mix of Enerplus' oil and gas production; the amount of future asset retirement obligations; future funds flow and debt-to-funds flow levels; potential asset sales; returns on Enerplus' capital program; Enerplus' tax position; sources of funding of Enerplus’ capital program; and future costs, expenses and royalty rates.*

The forward-looking information contained in this news release reflects several material factors and expectations and assumptions of Enerplus including, without limitation: that Enerplus will conduct its operations and achieve results of operations as anticipated; that Enerplus' 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 Enerplus' reserve and resource volumes; commodity price and cost assumptions; the continued availability of adequate debt and/or equity financing, cash flow and other sources to fund Enerplus' capital and operating requirements as needed; and the extent of its liabilities. Enerplus believes 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 news release 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 Enerplus' products; unanticipated operating results, results from development plans or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans by Enerplus or by third party operators of Enerplus' properties; increased debt levels or debt service requirements; inaccurate estimation of Enerplus' oil and gas reserves and resources 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 certain other risks detailed from time to time in Enerplus' public disclosure documents (including, without limitation, those risks identified in Enerplus' Annual Information Form and Form 40-F described above).

The forward-looking information contained in this news release speaks only as of the date of this news release, and none of Enerplus or its subsidiaries assume any obligation to publicly update or revise them to reflect new events or circumstances, except as may be required pursuant to applicable laws.

NON-GAAP MEASURES

In this news release, we use the terms "payout ratio" and "adjusted payout ratio" to analyze operating performance, leverage and liquidity, and the terms "F&D costs", "FD&A costs", "recycle ratio" and "operating netback" as measures of operating performance. We calculate "payout ratio" by dividing dividends to shareholders, net of our stock dividends and DRIP proceeds, by funds flow. "Adjusted payout ratio" is calculated as cash dividends to shareholders, net of our stock dividends and DRIP proceeds, plus capital spending (including office capital) divided by funds flow. "Operating netback" is calculated as oil and gas sales revenues after deducting royalties, operating costs and transportation. A "recycle ratio" is calculated as F&D costs divided by operating netback.

Enerplus believes that, in addition to net earnings and other measures prescribed by IFRS, the terms "payout ratio", "adjusted payout ratio", "F&D costs" and "FD&A costs" are useful supplemental measures as they provide an indication of the results generated by Enerplus' principal business activities. However, these measures are not measures recognized by GAAP and do not have a standardized meaning prescribed by IFRS. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers.

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Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation