NEWS RELEASE

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February 3, 2014
FOR IMMEDIATE RELEASE

Enerplus Exceeds Production Guidance for 2013 and Delivers Record Reserve Replacement

This news release includes forward-looking statements and information within the meaning of applicable securities laws. Readers are advised to review "Forward-Looking Information and Statements" at the conclusion of this news release. Readers are also referred to "Information Regarding Reserves 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 and operational information in this news release.

Calgary, Alberta - Enerplus Corporation ("Enerplus") (TSX: ERF) (NYSE: ERF) is pleased to announce production and reserve results for the year ended 2013. Highlights include:

2013 PRODUCTION

- Annual average production grew by over 9% in 2013 to average 89,800 BOE per day, ahead of our expectations of 89,000 BOE/day.
- Production during the month of December averaged 99,600 BOE per day, exceeding our expectations due to continued outperformance in the Marcellus, which averaged 170 MMcf per day during the month.
- Fourth quarter 2013 production averaged 94,200 BOE per day. As a result of the Marcellus performance, the natural gas weighting increased to 56% during the quarter.

2013 YEAR-END RESERVES

- Proved plus probable company interest ("2P") reserves grew by over 17% to 406 MMBOE. On a per share basis, 2P reserves increased by 15% year-over-year.
- Added 78 MMBOE of 2P reserves through our development programs, including technical and economic revisions, replacing 238% of 2013 annual production. Approximately 30% of the reserve additions were from crude oil.
- Added a total of 93 MMBOE of 2P reserves, including technical and economic revisions and net acquisition and development activity, replacing 284% of production in 2013. 83% of the total reserve additions were from natural gas.
- Capital spending for the year was an estimated $681.4 million, slightly less than our forecast of $685 million. Approximately two thirds of our capital was invested in oil projects in 2013.
- 2P finding and development ("F&D") costs including future development capital ("FDC") decreased by over 50% to $11.28 per BOE. This represents a recycle ratio of 2.4 times based upon an estimated operating netback of $27.40 per BOE in 2013.
- 2P finding, development and acquisition ("FD&A") costs per BOE were $8.36 per BOE including FDC, down over 60% year-over-year. Our three year FD&A costs for 2P reserves, including FDC, are $14.66 per BOE.

- A total of 24.4 MMbbls of 2P crude oil reserves were added through our acquisition and capital spending activities, including technical and economic revisions, reflecting a 175% oil production replacement and offsetting the disposition of 10 MMbbls of oil reserves during the year.

- 2P natural gas reserves increased by 43% to 1.2 Tcf with the addition of 463 Bcf associated with our development, acquisition and divestment activities. The majority of the increase in 2P natural gas reserves is attributable to the Marcellus where we added 268 Bcf of 2P reserves through our capital development activities, including technical and economic factors, and 143 Bcf through acquisitions. Total Marcellus 2P reserves at year-end increased to 601 Bcf and now represent 50% of our total 2P natural gas reserves, up from 27% at year-end 2012.

- 12.1 MMBOE of 2P reserves were sold during 2013 at an average cost of $33.72 per BOE.

- 26.9 MMBOE of 2P reserves were purchased during 2013, the majority of which is attributable to the acquisition of additional working interests in the Marcellus, at an average cost of $11.25 per BOE.

- 2P reserve life index remains essentially unchanged at 10.8 years.

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 89.5% of the total proved plus probable value (before tax, discounted at 10%) of our reserves at December 31, 2013. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated 74% of our Canadian reserves and 100% of the reserves associated with our U.S. oil assets. McDaniel also reviewed the internal evaluation completed by Enerplus on the remaining 26% of our Canadian assets. Netherland, Sewell & Associates, Inc. ("NSAI") evaluated all of our U.S. natural gas assets.

The following reserves information sets out our company interest reserves volumes at December 31, 2013 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 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.

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

RESERVES SUMMARY

Enerplus' 2P reserves increased by 60.2 million BOE to 406.0 million BOE at year-end 2013, up from 345.8 million at year-end 2012. The majority of reserve additions were associated with our U.S. properties as a result of our drilling and acquisition activities. These assets now represent 58% of total 2P reserves. Proved reserves as a percentage of total 2P reserves remained at 65% year-over-year.

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	64,108	26,700	90,808	7,348	354,385	212,770	192,681
Proved developed non-producing	805	136	941	145	8,486	72,320	14,553
Proved undeveloped	22,883	3,980	26,863	1,475	46,959	126,342	57,221
Total proved	87,795	30,816	118,611	8,967	409,830	411,431	264,455
Total probable	62,371	11,264	73,635	5,757	183,744	189,430	141,587
Proved plus Probable	**150,166**	**42,080**	**192,246**	**14,723**	**593,574**	**600,861**	**406,042**
Gross							
Proved producing	64,006	26,689	90,695	7,166	338,646	212,770	189,764
Proved developed non-producing	805	136	941	144	8,417	72,320	14,541
Proved undeveloped	22,879	3,980	26,859	1,422	43,215	126,342	56,540
Total proved	87,689	30,806	118,495	8,732	390,280	411,431	260,844
Total probable	62,340	11,260	73,600	5,629	174,445	189,430	139,875

Proved plus Probable	**150,029**	**42,066**	**192,095**	**14,361**	**564,725**	**600,861**	**400,720**
Net							
Proved producing	53,604	21,407	75,011	5,398	305,107	170,423	159,663
Proved developed non-producing	700	106	806	104	6,335	57,893	11,614
Proved undeveloped	18,654	3,053	21,707	1,172	42,789	101,084	46,858
Total proved	72,957	24,566	97,523	6,674	354,231	329,400	218,136
Total probable	50,388	8,588	58,976	4,459	158,767	151,530	115,152
Proved plus Probable	**123,345**	**33,154**	**156,499**	**11,134**	**512,998**	**480,930**	**333,288**

RESERVES RECONCILIATION

The following tables outline the changes in Enerplus' proved, probable and proved plus probable reserves, on a company interest basis, from December 31, 2012 to December 31, 2013:

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, 2012	36,246	31,521	67,767	6,887	361,158	-	134,847
Acquisitions	1,580	-	1,580	19	1,676	-	1,879
Dispositions	(7,105)	-	(7,105)	(599)	(5,999)	-	(8,703)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	1,511	1,528	3,039	196	24,172	-	7,264
Economic factors	491	55	546	(29)	(3,058)	-	8
Technical revisions	(105)	828	722	878	32,791	-	7,065
Production	(3,404)	(3,115)	(6,520)	(1,023)	(64,195)	-	(18,241)
Proved Reserves at Dec. 31, 2013	**29,214**	**30,816**	**60,030**	**6,330**	**346,545**	**-**	**124,118**

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, 2012	56,993	-	56,993	2,349	52,748	146,127	92,488
Acquisitions	30	-	30	2	12	117,668	19,645
Dispositions	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	5,188	-	5,188	255	5,177	168,634	34,412
Economic factors	(556)	-	(556)	2	(1,126)	(17,140)	(3,598)
Technical revisions	4,368	-	4,368	273	12,778	30,917	11,924
Production	(7,442)	-	(7,442)	(245)	(6,305)	(34,775)	(14,533)
Proved Reserves at Dec. 31, 2013	**58,581**	**-**	**58,581**	**2,637**	**63,285**	**411,431**	**140,337**

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, 2012	93,239	31,521	124,760	9,236	413,906	146,127	227,335
Acquisitions	1,610	-	1,610	21	1,688	117,668	21,524
Dispositions	(7,105)	-	(7,105)	(599)	(5,999)	-	(8,703)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	6,699	1,528	8,227	451	29,349	168,634	41,675

Economic factors	(65)	55	(10)	(26)	(4,183)	(17,140)	(3,590)
Technical revisions	4,262	828	5,090	1,151	45,569	30,917	18,989
Production	(10,846)	(3,115)	(13,961)	(1,267)	(70,499)	(34,775)	(32,774)
Proved Reserves at Dec. 31, 2013	**87,795**	**30,816**	**118,611**	**8,967**	**409,830**	**411,431**	**264,455**

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, 2012	12,810	10,991	23,801	3,144	171,526	-	55,533
Acquisitions	290	-	290	3	283	-	340
Dispositions	(2,775)	-	(2,775)	(214)	(2,164)	-	(3,350)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	687	1,751	2,438	70	8,489	-	3,923
Economic factors	(13)	57	45	(18)	(937)	-	(129)
Technical revisions	(1,320)	(1,536)	(2,856)	(421)	(32,227)	-	(8,649)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2013	**9,679**	**11,264**	**20,943**	**2,564**	**144,970**	**-**	**47,668**

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, 2012	43,111	-	43,111	2,243	27,202	78,373	62,950
Acquisitions	681	-	681	40	266	25,686	5,046
Dispositions	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	14,477	-	14,477	986	12,973	89,619	32,562
Economic factors	8	-	8	2	(19)	(8,877)	(1,473)
Technical revisions	(5,585)	-	(5,585)	(78)	(1,647)	4,629	(5,166)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2013	**52,692**	**-**	**52,692**	**3,193**	**38,774**	**189,430**	**93,919**

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, 2012	55,921	10,991	66,912	5,387	198,728	78,373	118,482
Acquisitions	971	-	971	43	548	25,686	5,386
Dispositions	(2,775)	-	(2,775)	(214)	(2,164)	-	(3,350)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	15,164	1,751	16,916	1,056	21,462	89,619	36,485
Economic factors	(5)	57	53	(16)	(956)	(8,877)	(1,602)
Technical revisions	(6,905)	(1,536)	(8,441)	(499)	(33,874)	4,629	(13,815)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2013	**62,371**	**11,264**	**73,635**	**5,757**	**183,744**	**189,430**	**141,587**

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, 2012	49,056	42,512	91,568	10,031	532,684	-	190,380
Acquisitions	1,870	-	1,870	23	1,959	-	2,219
Dispositions	(9,880)	-	(9,880)	(813)	(8,163)	-	(12,053)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	2,198	3,279	5,477	266	32,661	-	11,186
Economic factors	478	113	591	(46)	(3,995)	-	(121)
Technical revisions	(1,426)	(708)	(2,134)	457	564	-	(1,583)
Production	(3,404)	(3,115)	(6,520)	(1,023)	(64,195)	-	(18,241)
Proved Plus Probable Reserves at Dec. 31, 2013	**38,893**	**42,080**	**80,973**	**8,894**	**491,515**	**-**	**171,787**

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, 2012	100,104	-	100,104	4,592	79,950	224,500	155,438
Acquisitions	711	-	711	42	277	143,354	24,691
Dispositions	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	19,665	-	19,665	1,241	18,150	258,253	66,974
Economic factors	(548)	-	(548)	4	(1,145)	(26,017)	(5,071)
Technical revisions	(1,217)	-	(1,217)	196	11,131	35,545	6,758
Production	(7,442)	-	(7,442)	(245)	(6,305)	(34,775)	(14,533)
Proved Plus Probable Reserves at Dec. 31, 2013	**111,273**	**-**	**111,273**	**5,829**	**102,059**	**600,861**	**234,256**

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, 2012	149,160	42,512	191,672	14,623	612,634	224,500	345,817
Acquisitions	2,581	-	2,581	64	2,236	143,354	26,910
Dispositions	(9,880)	-	(9,880)	(813)	(8,163)	-	(12,053)
Discoveries	-	-	-	-	-	-	-
Extensions & improved recovery	21,864	3,279	25,143	1,507	50,811	258,253	78,160
Economic factors	(70)	113	43	(42)	(5,139)	(26,017)	(5,192)
Technical revisions	(2,643)	(708)	(3,351)	652	11,695	35,545	5,174
Production	(10,846)	(3,115)	(13,961)	(1,267)	(70,499)	(34,775)	(32,774)
Proved Plus Probable Reserves at Dec. 31, 2013	**150,166**	**42,080**	**192,246**	**14,723**	**593,574**	**600,861**	**406,042**

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 evaluators' best estimate of the capital required to bring the proved and proved plus 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 increase in FDC year-over-year is a result of the increase in the number of undeveloped drilling locations at Fort Berthold, the Marcellus, in the Wilrich and in our Canadian waterflood properties.

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

Future Development Capital	Proved Reserves	Proved Plus Probable Reserves
($ millions)		
2014	479	558
2015	390	518
2016	31	439
2017	31	376
2018	19	40
Remainder	51	65
Total FDC Undiscounted	1,001	1,996
Total FDC Discounted at 10%	889	1,667

F&D AND FD&A COSTS – *including future development capital*

($ millions except for per BOE amounts)	2013	2012	2011	3 Year
Proved Plus Probable Reserves				
Finding & Development Costs				
Capital Expenditures	$ 681.4	$ 852.8	$ 829.8	$ 2,364.0
Net change in Future Development Capital	$ 200.0	$ 534.6	$ 435.9	$ 1,170.5
Company Interest Reserve additions (MMBOE)	78.1	57.3	48.2	$ 183.6
F&D costs ($/BOE)	**$ 11.28**	**$ 24.21**	**$ 26.26**	**$ 19.25**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$ 561.1	$ 726.4	$ 370.2	$ 1,657.7
Net change in Future Development Capital	$ 216.6	$ 509.1	$ 402.7	$ 1,128.4
Company Interest Reserve additions (MMBOE)	93.0	53.9	43.2	$ 190.1
FD&A costs ($/BOE)	**$ 8.36**	**$ 22.92**	**$ 17.89**	**$ 14.66**
Proved Reserves				
Finding & Development Costs				
Capital Expenditures	$ 681.4	852.8	829.8	$ 2,364.0
Net change in Future Development Capital	$ (106.4)	248.3	230.7	$ 372.6
Company Interest Reserve additions (MMBOE)	57.1	38.4	31.5	$ 127.0
F&D costs ($/BOE)	**$ 10.08**	**$ 28.67**	**$ 33.67**	**$ 21.55**
Finding, Development & Acquisition Costs				
Capital expenditures and net acquisitions	$ 561.1	726.4	370.2	$ 1,657.7
Net change in Future Development Capital	$ (112.8)	241.3	213.0	$ 341.5
Company Interest Reserve additions (MMBOE)	69.9	36.6	28.9	$ 135.4
FD&A costs ($/BOE)	**$ 6.41**	**$ 26.44**	**$ 20.18**	**$ 14.77**

FORECAST PRICE ASSUMPTIONS

The estimated reserves volumes and the net present values of future net revenues ("NPV") at December 31, 2013 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of January 1, 2014. These prices were applied to the reserves evaluated by McDaniel and NSAI, along with those evaluated internally by Enerplus and reviewed by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below.

While the near-term oil and natural gas price assumptions used by our independent reserve evaluators at January 1, 2014 increased, the long-term price outlooks decreased when compared to the price assumptions used at December

31, 2012. As a result, despite a 17% increase in our 2P reserves at December 31, 2013, the estimated before tax NPV using a 10% discount increased by only 7%.

McDaniel January 2014 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$/MMBtu	Exchange Rate CDN$/US$
2014	95.00	95.00	67.50	4.25	4.00	0.950
2015	95.00	96.50	70.40	4.50	4.25	0.950
2016	95.00	97.50	71.20	4.75	4.55	0.950
2017	95.00	98.00	71.50	5.00	4.75	0.950
2018	95.30	98.30	71.80	5.25	5.00	0.950
Thereafter	**	**	**	**	**	0.950

(1) Edmonton Light Sweet 40 degree API, 0.3% sulphur content crude.
** Escalation varies after 2018.

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, before 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.

Net Present Value of Future Production Revenue – Forecast Prices and Costs *(before tax)*

Reserves at December 31, 2013, ($ Millions, discounted at)	**0%**	**5%**	**10%**	**15%**
Proved developed producing	$5,238	$3,820	$3,051	$2,575
Proved developed non-producing	299	217	174	147
Proved undeveloped	1,305	612	312	152
Total Proved	$6,842	$4,649	$3,537	$2,874
Probable	4,933	2,382	1,437	974
Total Proved Plus Probable Reserves (before tax)	$11,775	$7,031	$4,974	$3,848

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

INFORMATION REGARDING RESERVES AND OPERATIONAL INFORMATION

Currency

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

Barrels of Oil Equivalent
This news release also contains references to "BOE" (barrels of oil 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. BOEs 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, 2013, 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, 2013 ("**our AIF**") which will be available in late February 2014 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 be available on EDGAR at www.sec.gov. Readers are also urged to review the Management's Discussion & Analysis and financial statements to be filed on SEDAR and EDGAR concurrently with our AIF for more complete disclosure on our operations.*

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.

Other Metrics

Reserve life index is calculated by dividing the total applicable reserves quantity by the 2014 annual production as forecast in the reserves evaluations.

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.*

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 to bring reserves on production; the volumes and estimated net present value of Enerplus' oil and gas reserves 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 reserves and production; 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 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 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 ""F&D costs", "FD&A costs", "recycle ratio" and "operating netback" as measures of operating performance. "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 U.S. GAAP, the terms "recycle 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 U.S. GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers.

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Ian C. Dundas
President & Chief Executive Officer
Enerplus Corporation