NEWS RELEASE

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FOR IMMEDIATE RELEASE

ENERPLUS ANNOUNCES 2010 YEAR END RESULTS AND RESERVE INFORMATION

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 2010 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.

Effective January 1, 2011, Enerplus converted from an income trust structure with the parent entity being Enerplus Resources Fund (the "Fund") to a corporate structure with the parent entity being Enerplus Corporation, as successor issuer to the Fund. As the Fund was the public entity in existence at December 31, 2010, all financial information as at and for the year ended December 31, 2010 is presented with respect to the Fund and its outstanding trust units at that time.

Calgary, Alberta - Enerplus Corporation ("Enerplus") (TSX: ERF) (NYSE: ERF) is pleased to announce operating, financial and reserve results for 2010. Over the past two years, we have been transitioning our asset base in order to create a portfolio that combines low decline, cash generating properties together with earlier stage assets that can provide future production and reserves growth. Throughout this period, we have sold approximately $1.0 billion of non-core assets, including the majority of our interests in the oil sands, and replaced these properties with $1.3 billion of new assets that offer significant near-term cash flow and organic growth potential. Along with changes to our asset base, we have also added significantly to our internal technical expertise in order to effectively manage our existing and growing portfolios in both Canada and the U.S. These changes have been essential in advancing our strategy to deliver both income and growth to our investors and improve our focus, profitability and the overall competitiveness of our business within the North American oil and gas industry.

Our 2010 results clearly indicate progress on this strategy. Our development capital spending program delivered our highest level of reserve additions in our history. However, our shallow gas assets continue to be faced with challenging economics due to declining natural gas prices, reduced capital spending and reservoir under-performance.

As a result of our activities, we believe Enerplus is now well-positioned to deliver competitive returns to investors. We have preserved our financial strength through our transition and expect to utilize our balance sheet to increase our capital spending over the next two years. We intend to continue to distribute a portion of the cash flow generated from our operations to investors through a monthly dividend and expect to complement this with annual growth in production and reserves per share.

STRATEGIC EXECUTION

- Enerplus acquired over $1 billion of prospective land in 2010 representing almost 300,000 net acres in key resource plays in North America that offer superior economic returns. As a result of these acquisitions, Enerplus now holds the following significant land positions in key resource plays:

  - Marcellus – ~130,000 net non-operated acres and ~70,000 net operated acres in Pennsylvania, Maryland and West Virginia
  - Bakken – ~75,000 net acres at Fort Berthold in North Dakota and ~155,000 net acres in southeast Saskatchewan
  - Deep Basin – ~80,000 net acres in Alberta and British Columbia that is prospective for the Montney and Mannville

- Throughout 2010 we actively pursued a strategic portfolio rationalization, selling approximately 10,400 BOE/day of non-core conventional oil and gas production in order to improve our operational focus and profitability. In addition, we also sold our Kirby oil sands lease. Total proceeds from these divestment activities amounted to $871.5 million.
- Our acquisition activities were funded primarily through disposition proceeds, thereby keeping our balance sheet strong and providing us with the financial flexibility required to support our capital spending plans over the next two years.
- The “best estimate” of contingent resources associated with our Marcellus interests increased 63% from 2.4 trillion cubic feet to 3.9 trillion cubic feet of natural gas at December 31, 2010. The increase in contingent resources is attributable to our acquisition of additional operated interests in West Virginia and Maryland (0.9 trillion cubic feet) and an improvement in performance of wells drilled on our non-operated leases (0.6 trillion cubic feet).
- The “best estimate” of contingent resources associated with our North Dakota Bakken crude oil leases was 60 MMBOE at December 31, 2010, 17% higher than our previous estimate, with 90 future drilling locations identified. This assessment reflects only the Bakken resource at this time as we do not have enough wells completed in the Three Forks zone to make an appropriate estimate.
- Enerplus now has over 700 million BOE of contingent resources associated with our North Dakota and Marcellus properties which provides us with significant growth potential in the coming years.
- Enerplus investors realized positive returns in 2010 with Canadian investors realizing a 35.6% total return and U.S. investors realizing a 43.4% total return. The return to our U.S. investors also reflected the appreciation of the Canadian dollar throughout the year.

OPERATIONS

- Enerplus produced an average of 83,139 BOE/day in 2010, in line with our guidance of 83,000 – 84,000 BOE/day. Daily production volumes were 8,430 BOE/day lower than the average daily volumes in 2009 due to reduced capital spending in 2009 and the sale of 10,400 BOE/day of non-core production in 2010.
- Production volumes for the month of December were 77,200 BOE/day, approximately 4% lower than our guidance of 80,000 – 82,000 BOE/day. Exit volume shortfalls were primarily associated with our Bakken production in North Dakota where extreme weather conditions in December impacted our ability to truck production to the sales terminals. Additionally, two long lateral Bakken wells which were originally slated for completion in early December were delayed. Both of these wells are now on stream with initial production rates of 1,500 bbls/day per well.
- Operating costs averaged $9.54/BOE during 2010, 6% better than our guidance of $10.20/BOE primarily as a result of the sale of high-cost non-core production and lower repairs, maintenance and electricity costs.
- In 2010, we invested $543 million through our capital program, an increase of over 80% from our spending levels in 2009. This was higher than our forecast capital spending of $515 million due in part to an increase in drilling and completion costs associated with our Marcellus program. Approximately $424 million was invested in drilling, completions and recompletions, $85 million in facilities and maintenance, and $34 million in seismic and lease rentals.
- Almost 60% of our development spending related to oil projects where we concentrated our efforts on our Bakken and waterflood assets. Over half of our natural gas spending occurred in the Marcellus where we were focused on delineation and lease retention activities, and drilling in the more prolific northeast area of Pennsylvania. Spending on our Canadian natural gas assets declined throughout the year due to low economic returns in this price environment. Because of long lead times for well completion and tie-ins in the Bakken and more particularly in the Marcellus, much of the capital spending in 2010 will not generate production and cash flow until 2011.

- A total of 225.2 net wells were drilled in 2010. Excluding 103.7 net shallow gas wells, the majority of which were drilled to take advantage of the Alberta Drilling Royalty Credit program, Enerplus drilled 121.5 net wells, 77% of which were crude oil wells. Over 80% of these wells were horizontal.

FINANCIAL

- Cash flow from operations totaled $703.1 million, down 9% from 2009 due to lower production volumes.
- We distributed $384.1 million to Unitholders through monthly distributions in 2010, representing 55% of cash flow from operating activities. When distributions and development capital spending are combined, our adjusted payout ratio for 2010 was 132%.
- We realized cash hedging gains of $49.7 million in 2010. Our natural gas contracts generated gains of $67.3 million while our crude oil contracts experienced losses of $17.6 million.
- General and administrative costs were $2.60/BOE, slightly higher than our guidance of $2.55/BOE and similar to 2009 levels.
- Our trailing 12 month debt-to-cash flow ratio was 1.0x at December 31, 2010.

RESERVES

- Total proved plus probable ("P+P") company interest reserves at December 31, 2010 were 306.2 MMBOE, down approximately 11% from year-end 2009 approximately 60% of this decline attributable to the sale of non-core properties net of acquisitions. Proved reserves totaled 219.4 MMBOE, representing approximately 72% of total proved plus probable reserves. 53% of P+P reserves are weighted to crude oil and natural gas liquids. Our P+P reserve life index was 10.7 years.

- 34.0 MMBOE of P+P reserves were sold during 2010 of which 23.4 MMBOE were attributable to oil properties and 63.9 Bcfe were related to natural gas properties.

- 11.8 MMBOE of P+P reserves were acquired in 2010, primarily in our Fort Berthold, North Dakota Bakken oil property. The majority of our acquisitions in 2010 were of undeveloped land with nominal proved or probable reserves.

- Our development capital spending replaced 114% of 2010 production before revisions. 34.7 MMBOE of P+P reserves were added from our delineation and development activities comprised of 16.8 MMBOE from our oil properties and 107.3 Bcfe from our natural gas properties.

- The majority of the additions were attributable to our North Dakota Bakken and Marcellus resource plays at 11.0 MMBOE and 87.6 Bcfe respectively. Our Finding & Development costs ("F&D") were $10.74/BOE at Fort Berthold and $1.64/Mcfe in the Marcellus. Booked drilling locations for these areas in our reserve report represent less than one year's drilling activity based upon current plans. We also added 5.7 MMBOE in Canada across various oil properties, including our waterfloods, and 9.0 Bcfe from our deep tight gas plays.

- A decrease in the outlook for natural gas prices and underperformance in a few properties resulted in negative revisions to our natural gas properties of 108.5 Bcfe of P+P reserves and 2.6 MMBOE of P+P reserves associated with our oil properties for a total of 20.7 MMBOE of P+P reserves. The majority of the negative revisions were associated with our shallow gas assets. Roughly 40% or 45 Bcfe of our natural gas revisions related to the decline in natural gas price forecasts, while 63.5 Bcfe related to performance mainly in our Shackleton shallow gas property where well interference has changed our view on long-term performance and economics. The net present value of the performance revisions at Shackleton discounted at 10% was approximately $100 million or 2% of our 2010 year-end proved plus probable reserve value discounted at 10%. Approximately 567 natural gas locations were removed from our reserve report along with $95.6 million of associated future development capital. Of the total 20.7 MMBOE in revisions, 6.9 MMBOE or roughly one third were in the proved category. After these revisions, approximately 150 shallow gas drilling locations associated with our Shackleton property remain in our reserve report.

- The net present value of our P+P reserves (future prices discounted at 10%) was approximately $4.8 billion at December 31, 2010, down from $5.6 billion at December 31, 2009 primarily due to the sale of booked reserves and lower forecast natural gas prices.

- Our F&D cost per BOE of P+P reserves including future development costs, before reserve revisions, was $17.46 with a recycle ratio of 1.6x. This was primarily a result of the reserve additions from our new growth properties in the Bakken and the Marcellus.
- After accounting for the negative revisions attributable primarily to our shallow natural gas assets, our F&D cost was $36.71/BOE with a recycle ratio of 0.75x.
- As we acquired predominantly undeveloped land in early stage growth properties in 2010 with significant potential but few reserves, and sold non-core properties with proved plus probable reserves, the calculation of our Finding, Development & Acquisition costs resulted in a negative amount for the year.

SELECTED FINANCIAL AND OPERATING HIGHLIGHTS

SELECTED FINANCIAL RESULTS	Three months ended December 31,		Twelve months ended December 31,	
(in Canadian dollars)	**2010**	2009	**2010**	2009
Financial (000's)				
Cash Flow from Operating Activities	**$146,787**	$188,579	**$703,148**	$775,786
Cash Distributions to Unitholders[1]	**96,396**	95,550	**384,128**	368,201
Excess of Cash Flow Over Cash Distributions	**50,391**	93,029	**319,020**	407,585
Net Income / (Loss)	**(995)**	2,718	**127,112**	89,117
Debt Outstanding – net of cash	**724,031**	485,349	**724,031**	485,349
Development Capital Spending	**229,029**	118,889	**542,679**	299,111
Acquisitions	**524,338**	49,100	**1,018,069**	271,977
Divestments	**537,935**	102,070	**871,458**	104,325
Actual Cash Distributions to Unitholders per Trust Unit	**$0.54**	$0.54	**$2.16**	$2.23
Financial per Weighted Average Trust Unit[2]				
Cash Flow from Operating Activities	**$0.82**	$1.07	**$3.96**	$4.58
Cash Distributions[1]	**0.54**	0.54	**2.16**	2.17
Excess of Cash Flow Over Cash Distributions	**0.28**	0.53	**1.80**	2.41
Net Income	**(0.01)**	0.02	**0.72**	0.53
Payout Ratio[3]	**66%**	51%	**55%**	47%
Adjusted Payout Ratio[3]	**223%**	114%	**132%**	87%
Selected Financial Results per BOE[4]				
Oil & Gas Sales[5]	**$ 42.49**	$ 41.75	**$ 42.85**	$ 36.89
Royalties	**(6.21)**	(6.56)	**(7.37)**	(6.21)
Commodity Derivative Instruments	**1.02**	3.34	**1.64**	4.66
Operating Costs	**(8.29)**	(9.27)	**(9.61)**	(9.71)
General and Administrative Expenses	**(2.97)**	(3.30)	**(2.40)**	(2.44)
Interest, Foreign Exchange and Other Expenses	**(2.95)**	(0.72)	**(1.85)**	(0.34)
Taxes	**(0.40)**	0.66	**1.00**	(0.01)
Asset Retirement Obligations Settled	**(0.96)**	(0.63)	**(0.57)**	(0.41)
Cash Flow from Operating Activities before changes in non-cash working capital	**$ 21.73**	$ 25.26	**$ 23.69**	$ 22.43
Weighted Average Number of Trust Units Outstanding[2]	**178,368**	176,872	**177,737**	169,280
Debt to Trailing 12 Month Cash Flow Ratio	**1.0x**	0.6x	**1.0x**	0.6x

SELECTED OPERATING RESULTS	Three months ended December 31, 2010	2009	Twelve months ended December 31, 2010	2009
Average Daily Production				
Natural Gas (Mcf/day)	**274,314**	305,691	**288,692**	326,570
Crude Oil (bbls/day)	**30,368**	31,590	**31,135**	32,984
NGLs (bbls/day)	**4,027**	4,238	**3,889**	4,157
Total (BOE/day)	**80,114**	86,777	**83,139**	91,569
% Crude Oil & Natural Gas Liquids	**43%**	41%	**42%**	41%
Average Selling Price (5)				
Natural Gas (per Mcf)	**$ 3.63**	$ 4.06	**$ 4.05**	$ 3.91
Crude Oil (per bbl)	**72.18**	67.90	**70.38**	58.54
NGLs (per bbl)	**53.66**	56.96	**51.41**	41.54
US$/CDN$ exchange rate	**0.99**	0.95	**0.97**	0.88
Net Wells drilled	**40**	156	**225**	313

(1) Calculated based on distributions paid or payable.
(2) Weighted average trust units outstanding for the period, includes the equivalent exchangeable limited partnership units.
(3) Payout ratio is calculated as cash distributions to unitholders divided by cash flow from operating activities. Adjusted payout ratio is calculated as the sum of cash distributions to unitholders plus development capital and office expenditures divided by cash flow from operating activities. See "Non-GAAP Measures" below.
(4) Non-cash amounts have been excluded.
(5) Net of oil and gas transportation costs, but before the effects of commodity derivative instruments.

TRUST UNIT TRADING SUMMARY For the twelve months ended December 31, 2010	CDN* – ERF.un (CDN$)	U.S.** - ERF (US$)
High	**$31.85**	**$31.83**
Low	**$18.22**	**$13.76**
Close	**$30.67**	**$30.84**

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

2010 CASH DISTRIBUTIONS PER TRUST UNIT	CDN$	US$
First Quarter Total	**$0.54**	**$0.52**
Second Quarter Total	**$0.54**	**$0.53**
Third Quarter Total	**$0.54**	**$0.52**
Fourth Quarter Total	**$0.54**	**$0.52**
Total	**$2.16**	**$2.09**

2010 PRODUCTION AND CAPITAL SPENDING

Play Type	**2010 Average Daily Production**	**2010 Exit Production (Dec. mth)**	**2010 Capital Expenditures* ($ millions)**	**2010 Incremental Initial Production****
Bakken/Tight Oil (BOE/day)	11,305	13,300	$172	11,445
Crude Oil Waterflood (BOE/day)	14,688	13,790	127	2,087
Conventional Oil (bbls/day)	8,535	5,969	22	865
Total Crude Oil (BOE/day)	34,528	33,060	$321	14,397
Marcellus Shale Gas (Mcfe/day)	9,338	17,662	$123	22,140
Shallow Gas (Mcfe/day)	117,598	103,921	26	62,046
Tight Gas (Mcfe/day)	85,084	86,661	65	21,258
Conventional Gas (Mcfe/day)	79,649	56,579	8	32,964
Total Gas (Mcfe/day)	291,669	264,823	$222	138,408
Company Total (BOE/day)	83,139	77,197	$543	18,242

*Net of $18.3 million in Alberta Drilling Royalty Credits
**Based upon first full calendar month of sales

2010 NET DRILLING ACTIVITY*

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-in**	Wells On-stream	Dry & Abandoned Wells
Bakken/Tight Oil	28.5	0.9	29.4	5.5	23.8	-
Crude Oil Waterfloods	38.9	8.4	47.3	16.5	30.1	0.6
Conventional Oil	16.6	0.0	16.6	4.7	11.9	-
Total Oil	**83.9**	**9.3**	**93.2**	**26.8**	**65.8**	**0.6**
Marcellus Shale Gas	12.2	1.5	13.6	10.2	3.1	0.3
Shallow Gas	-	103.7	103.7	63.4	40.4	-
Tight Gas	4.2	2.1	6.3	5.1	1.2	-
Conventional Gas	1.7	6.6	8.3	3.1	5.3	-
Total Gas	**18.1**	**113.9**	**132.0**	**81.8**	**49.9**	**0.3**
Company Total	**102.0**	**123.2**	**225.2**	**108.5**	**115.7**	**0.9**

*Totals may not add due to rounding
**Pending potential completion/tie-in or abandonment and on-stream wells measured as at December 31, 2010

KEY RESOURCE PLAY ACTIVITY

Bakken/Tight Oil

Our Bakken/Tight Oil resource play grew significantly in 2010 through the acquisition of undeveloped acreage in North Dakota and Saskatchewan. Through a series of acquisitions, we now hold over 220,000 net acres of undeveloped land that is prospective for the Bakken and the Three Forks in certain areas. Total production from this resource play grew by 12% year-over-year with the increase in production coming primarily from our drilling activity in North Dakota. In total, over 12.1 MMBOE of reserves were added through our development activities, with another 11.3 MMBOE added through acquisitions. We also added 60.0 MMBOE of “best estimate” contingent resource at Fort Berthold attributable to the Bakken only which represents approximately 90 future drilling locations. We believe this provides us with significant future growth potential in the coming years.

In 2010, the majority of our drilling activity occurred in our U.S. Bakken assets where we drilled 6.4 net horizontal wells at Sleeping Giant and another 14.8 net horizontal wells at Fort Berthold. Our drilling results to date in the Fort Berthold area have generally exceeded our expectations and are the basis for our increase in capital spending planned in 2011. We also drilled a number of wells in Saskatchewan targeting the Bakken on both our operated leases and through our non-operated working interest at Taylorton. The drilling results on our operated leases have been disappointing. While we’ve discovered oil in this area, the limited quantity does not meet current economic thresholds. We are continuing to evaluate seismic data from the area to assess the potential of the Bakken and other zones.

We expect to spend approximately $300 million, almost half of our 2011 capital budget, on our Bakken oil properties. Based upon the success of our drilling activities in Fort Berthold, $230 million has been targeted for this area as we move into the development phase. We plan to drill 32 net operated wells at Fort Berthold with at least 75% of these wells planned as long lateral horizontal wells. Our primary target will be the Bakken formation however we also plan to test the Three Forks formation underlying the Bakken to evaluate the potential and future prospectivity of this zone. We have secured service agreements for frac crews, proppant and a drilling rig to support the successful execution of our program. We’re also working to have mid-stream agreements in place by mid-year that will allow us to tie in our production and capture the associated natural gas. The remaining $70 million will be invested at Sleeping Giant in Montana and in our Canadian tight oil properties.

We expect production at Fort Berthold will more than double as we exit 2011 with total production from our Bakken/Tight Oil resource play growing by 50% throughout 2011, exiting in the range of 18,000 – 21,000 BOE/day. Given the high initial productivity of these wells and the competition for services in this region, exit production volumes and capital spending could vary from guidance depending upon when new wells are drilled, completed and tied in.

Waterfloods

Our crude oil waterflood assets are a core part of our business contributing low decline, stable production and free cash flow to support investment in our new growth plays. This portfolio includes a variety of properties producing from formations such as the Cardium, Viking, Ratcliffe, Lloydminster and Glauconitic that offer new drilling opportunities, optimization and enhanced oil recovery potential. Through horizontal drilling technology and reservoir depletion analysis, we have identified new opportunities in a number of these mature fields that we believe will help offset declines and, in some areas, provide a modest level of growth. Our activities in 2010 were focused on drilling and recompletion activities and facility upgrades. As a result of our land acquisitions in Saskatchewan, we expanded the potential at Freda Ratcliffe. We've drilled nine horizontal wells into the existing unit and expect that we have an additional 16 locations. We are also turning our attention to other lands on the Ratcliffe trend and believe that they provide significant additional opportunities. We also started work on our first polymer pilot at Giltedge which will continue through 2011. Approximately 53% of our waterflood capital spending was directed toward drilling both producing and injector wells including completion activities.

We expect to spend approximately $110 million on our waterflood assets in 2011 maintaining production volumes throughout the year at approximately 14,000 BOE/day. We will also continue to advance the work on our enhanced oil recovery pilot projects. A significant portion of this capital is being directed to activities that we believe will position us for future production and reserve growth.

Marcellus Shale Gas

We continued to add to our Marcellus interests in 2010 through the acquisition of operated interests in Pennsylvania, West Virginia and Maryland. Through three transactions, we acquired 70,000 net acres of land, taking our total interests in the Marcellus to approximately 200,000 net acres. As a result of our acquisition activities as well as improved well performance, the contingent resource estimate associated with our Marcellus leases increased by 63% to 3.9 Tcfe of natural gas, more than 4.5 times our total corporate natural gas proved plus probable reserves. We also booked approximately 96 Bcfe of proved plus probable reserves at year end. Our finding and development costs for the Marcellus were $1.64/Mcfe.

A majority of the activity in 2010 was with our operating partner, Chief Oil & Gas, where we participated in the drilling of 60 gross wells (11.7 net wells) during the year. We also participated in another 62 gross wells (1.9 net wells) during 2010 with other operators. We planned to have 67 gross wells tied-in during 2010, however, due to the timing of pipeline infrastructure and the availability of frac crews, only 38 gross wells were tied in. Despite these delays, we exited 2010 on track with production of approximately 91 MMcf/day gross of natural gas (18 MMcf/day net to Enerplus) as actual well results are exceeding our original expectations. We estimate that there is currently 120 – 140 MMcf/day of natural gas waiting on completion or tie-in, in which we have a 20% working interest. We also began drilling our first operated well in Centre County in 2010. The well was completed in January of this year but we do not expect tie-in until late 2011 due to current infrastructure and gathering limitations.

Approximately $160 million of capital expenditures are planned for the Marcellus in 2011, with the majority being spent on our non-operated interests. With our joint venture partners, we plan to have eight to ten rigs working throughout the play in 2011 and expect to drill 150 gross wells (22.4 net). We also expect to complete approximately 121 wells and plan to have 94 new wells on stream by the end of the year. We also plan to drill five gross operated delineation wells (4 net) on our new Marcellus leases. Due to the timing of infrastructure, access to frac crews and permitting, the estimated cycle time from commencement of drilling to production tie-in is approximately nine months. As a result of this timeframe, close to 75% of the wells that we plan to drill in 2011 will not be tied-in until 2012. As well, with the high activity levels in this region, well costs could come under pressure throughout the year. Despite these delays, production in 2011 is expected to grow by 150% to approximately 45 MMcf/day by year-end.

RESERVES

All reserves are presented on a "company interest" basis. See "Information Regarding Reserves, Resources and Operational Information" at the end of this news release for information regarding the presentation of company interest reserves.

All of our reserves, including our U.S. reserves, were evaluated using Canadian National Instrument 51-101 ("NI 51-101") standards. McDaniel & Associates Consultants Ltd. ("McDaniel") evaluated or reviewed all of our Canadian assets, and in August 2010, Enerplus contracted McDaniel to replace Netherland, Sewell & Associates, Inc. as our independent reserve evaluator for our western United States assets. Haas Petroleum Engineering Services Inc. ("Haas") has evaluated our Marcellus shale gas assets again this year.

McDaniel has evaluated 86% of the total proved plus probable value (discounted at 10%) of our Canadian conventional year-end reserves and reviewed the internal evaluation completed by Enerplus on the remaining 14% of reserves. McDaniel also evaluated substantially all of the reserves associated with our western U.S. assets with the exception of some minor royalty interest properties which were evaluated internally and reviewed by McDaniel. The evaluation of contingent resources associated with our Bakken leases at Fort Berthold was conducted by Enerplus and reviewed by McDaniel. Haas evaluated 100% of our Marcellus shale gas assets in the U.S. and provided both the reserve and contingent resource estimates.

Reserves & Contingent Resources by Resource Play

Play Types	Proved	Proved plus Probable Reserves	Proved plus Probable Booked Net Drilling Locations	"Best Estimate" Contingent Resources*	Incremental Future Contingent Resource Net Drilling Locations
Bakken/Tight Oil (MMBOE)	38.0	57.5	39	60	90
Crude Oil Waterfloods (MMBOE)	65.2	83.7	45	-	-
Other Conventional Oil (MMBOE)	20.8	27.7	23	-	-
Total Oil (MMBOE)	124.0	168.9	107	60	90
Marcellus Shale Gas (Bcfe)	52.4	117.2	13	3,904	926
Tight Gas (Bcfe)	228.7	320.8	40	-	-
Shallow Gas (Bcfe)	164.8	220.5	152	-	-
Other Conventional Gas (Bcfe)	126.3	165.0	1	-	-
Total Gas (Bcfe)	572.2	823.5	206	3,904	926
Total Company (MMBOE)	**219.4**	**306.2**	**313**	**710.7**	**1,016**

*Contingent resources net to Enerplus. No contingent resource assessment has been conducted on our waterflood, tight gas, shallow gas or other conventional oil and gas assets at this time.

Reserves Summary

The following table sets out our company interest volumes at December 31, 2010 by production type and reserve category under McDaniel's forecast price scenario set forth below in this news release. Under different price scenarios, these reserves could vary as a change in price can affect the economic limit and reserves associated with a property.

2010 Reserves Summary – Company Interest Volumes (Forecast Prices)

Reserves Category	Light & Medium Oil (Mbbls)	Heavy Oil (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (Mbbls)	Natural Gas (MMcf)	Shale Gas (MMcf)	Total (MBOE)
Proved Developed Producing							
Canada	46,028	25,955	71,983	7,627	456,777	-	155,739
United States	21,880	-	21,880	67	34,566	32,014	33,044
Total Proved Developed Producing	67,908	25,955	93,863	7,694	491,343	32,014	188,783
Proved Developed Non-Producing							
Canada	347	687	1,034	175	12,883	-	3,357
United States	1,193	-	1,193	1	1,115	2,508	1,798
Total Proved Developed Non-Producing	1,540	687	2,227	176	13,998	2,508	5,155
Proved Undeveloped						-	
Canada	3,233	2,535	5,768	713	40,389	-	13,212
United States	7,848	-	7,848	27	8,360	17,703	12,219
Total Proved Undeveloped	11,081	2,535	13,616	740	48,749	17,703	25,431
Proved						-	
Canada	49,608	29,177	78,785	8,515	510,049	-	172,308
United States	30,921	-	30,921	95	44,041	52,225	47,061
Total Proved	80,529	29,177	109,706	8,610	554,090	52,225	219,369
Probable						-	
Canada	14,098	9,783	23,881	2,825	173,983	-	55,703
United States	16,266	-	16,266	141	24,114	64,437	31,165

Total Probable	30,364	9,783	40,147	2,966	198,097	64,437	86,868
Proved Plus Probable						-	
Canada	63,706	38,960	102,666	11,340	684,032	-	228,011
United States	47,187	-	47,187	236	68,155	116,662	78,226
Total Proved Plus Probable	110,893	38,960	149,853	11,576	752,187	116,662	306,237

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, 2009 to December 31, 2010.

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, 2009	61,053	34,431	95,484	10,633	696,585	-	222,214
Acquisitions	249	-	249	30	2,235	-	652
Dispositions	(11,001)	(4,207)	(15,208)	(1,346)	(50,085)	-	(24,902)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	3,505	15	3,520	138	12,431	-	5,730
Economic Factors	(86)	(17)	(103)	(230)	(33,414)	-	(5,902)
Technical Revisions	866	1,902	2,768	709	(20,366)	-	83
Production	(4,978)	(2,947)	(7,925)	(1,419)	(97,337)	-	(25,567)
Proved Reserves at Dec. 31, 2010	49,608	29,177	78,785	8,515	510,049	-	172,308

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, 2009	25,452	-	25,452	120	49,449	8,127	35,168
Acquisitions	4,799	-	4,799	-	1,191	-	4,998
Dispositions	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	6,379	-	6,379	27	2,096	35,767	12,717
Economic Factors	40	-	40	-	12	-	42
Technical Revisions	(2,329)	-	(2,329)	(33)	(4,035)	11,696	(1,085)
Production	(3,420)	-	(3,420)	(19)	(4,672)	(3,365)	(4,779)
Proved Reserves at Dec. 31, 2010	30,921	-	30,921	95	44,041	52,225	47,061

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, 2009	86,505	34,431	120,936	10,753	746,034	8,127	257,382
Acquisitions	5,048	-	5,048	30	3,426	-	5,650
Dispositions	(11,001)	(4,207)	(15,208)	(1,346)	(50,085)	-	(24,902)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	9,884	15	9,899	165	14,527	35,767	18,447
Economic Factors	(46)	(17)	(63)	(230)	(33,402)	-	(5,860)
Technical Revisions	(1,463)	1,902	439	676	(24,401)	11,696	(1,002)
Production	(8,398)	(2,947)	(11,345)	(1,438)	(102,009)	(3,365)	(30,346)
Proved Reserves at Dec. 31, 2010	80,529	29,177	109,706	8,610	554,090	52,225	219,369

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, 2009	16,776	12,347	29,123	3,718	250,061	-	74,518
Acquisitions	56	-	56	17	(1,004)	-	(95)
Dispositions	(4,060)	(1,650)	(5,710)	(447)	(17,930)	-	(9,145)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	1,699	10	1,709	84	6,991	-	2,958
Economic Factors	(34)	(16)	(50)	(21)	(15,150)	-	(2,596)
Technical Revisions	(339)	(908)	(1,247)	(526)	(48,985)	-	(9,937)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2010	14,098	9,783	23,881	2,825	173,983	-	55,703

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, 2009	7,287	-	7,287	36	17,085	16,763	12,964
Acquisitions	5,890	-	5,890	-	2,359	-	6,283
Dispositions	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	4,129	-	4,129	70	3,016	51,325	13,255
Economic Factors	38	-	38	-	33	-	44
Technical Revisions	(1,078)	-	(1,078)	35	1,621	(3,651)	(1,381)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2010	16,266	-	16,266	141	24,114	64,437	31,165

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, 2009	24,063	12,347	36,410	3,754	267,146	16,763	87,482
Acquisitions	5,946	-	5,946	17	1,355	-	6,188
Dispositions	(4,060)	(1,650)	(5,710)	(447)	(17,930)	-	(9,145)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	5,828	10	5,838	154	10,007	51,325	16,213
Economic Factors	4	(16)	(12)	(21)	(15,117)	-	(2,552)
Technical Revisions	(1,417)	(908)	(2,325)	(491)	(47,364)	(3,651)	(11,318)
Production	-	-	-	-	-	-	-
Probable Reserves at Dec. 31, 2010	30,364	9,783	40,147	2,966	198,097	64,437	86,868

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, 2009	77,829	46,778	124,607	14,351	946,646	-	296,732
Acquisitions	305	-	305	47	1,231	-	557
Dispositions	(15,061)	(5,857)	(20,918)	(1,793)	(68,015)	-	(34,047)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	5,204	25	5,229	222	19,422	-	8,688
Economic Factors	(120)	(33)	(153)	(251)	(48,564)	-	(8,498)
Technical Revisions	527	994	1,521	183	(69,351)	-	(9,854)
Production	(4,978)	(2,947)	(7,925)	(1,419)	(97,337)	-	(25,567)
Proved Plus Probable Reserves at Dec. 31, 2010	**63,706**	**38,960**	**102,666**	**11,340**	**684,032**	**-**	**228,011**

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, 2009	32,739	-	32,739	156	66,534	24,890	48,132
Acquisitions	10,689	-	10,689	-	3,550	-	11,281
Dispositions	-	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	10,508	-	10,508	97	5,112	87,092	25,972
Economic Factors	78	-	78	-	45	-	86
Technical Revisions	(3,407)	-	(3,407)	2	(2,414)	8,045	(2,466)
Production	(3,420)	-	(3,420)	(19)	(4,672)	(3,365)	(4,779)
Proved Plus Probable Reserves at Dec. 31, 2010	**47,187**	**-**	**47,187**	**236**	**68,155**	**116,662**	**78,226**

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, 2009	110,568	46,778	157,346	14,507	1,013,180	24,890	344,864
Acquisitions	10,994	-	10,994	47	4,781	-	11,838
Dispositions	(15,061)	(5,857)	(20,918)	(1,793)	(68,015)	-	(34,047)
Discoveries	-	-	-	-	-	-	-
Extensions & Improved Recovery	15,712	25	15,737	319	24,534	87,092	34,660
Economic Factors	(42)	(33)	(75)	(251)	(48,519)	-	(8,412)
Technical Revisions	(2,880)	994	(1,886)	185	(71,765)	8,045	(12,320)
Production	(8,398)	(2,947)	(11,345)	(1,438)	(102,009)	(3,365)	(30,346)
Proved Plus Probable Reserves at Dec. 31, 2010	**110,893**	**38,960**	**149,853**	**11,576**	**752,187**	**116,662**	**306,237**

NET PRESENT VALUE OF FUTURE PRODUCTION REVENUE

The estimated reserve volumes and net present values of all future net revenues at December 31, 2010 were based upon forecast crude oil and natural gas pricing assumptions prepared by McDaniel as of December 31, 2010. These prices were applied to the reserves evaluated by McDaniel and Haas, along with those evaluated internally by Enerplus and audited by McDaniel. The base reference prices and exchange rates used by McDaniel are detailed below:

McDaniel January 2011 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$
2011	85.00	84.20	66.70	4.55	4.25	0.975
2012	87.70	88.40	68.70	5.30	4.90	0.975
2013	90.50	91.80	68.60	5.75	5.40	0.975
2014	93.40	94.80	70.80	6.30	5.90	0.975
2015	96.30	97.70	73.00	6.80	6.35	0.975
Thereafter	**	**	**	**	**	0.975

(1) Edmonton Light Sweet 40 degree API, 0.3% sulphur content crude

** Escalation varies after 2015

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 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, 2010, ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	6,370	4,230	3,222	2,635
Proved developed non-producing	158	116	90	74
Proved undeveloped	754	456	297	200
Total Proved	**7,282**	**4,802**	**3,609**	**2,909**
Probable	3,940	1,931	1,181	816
Total Proved Plus Probable Reserves	**11,222**	**6,733**	**4,790**	**3,725**

NET ASSET VALUE

Enerplus' estimated net asset value is 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. This calculation can vary significantly depending on the oil and natural gas price assumptions used by the independent reserve engineers.

In addition, this calculation ignores "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, 2010, the estimate of contingent resources contained within our leases was in excess of 700 million BOE, more than 2.3 times our proved plus probable reserves. As we execute our capital programs, we expect to convert contingent resources to reserves and significantly increase the value of these assets.

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, 2010)

($ millions except trust unit amounts, discounted at)	**0%**	**5%**	**10%**	**15%**
Total net present value of proved plus probable reserves (before tax)	$11,222	$6,733	$4,790	$3,725
Undeveloped acreage (2010 Year End) (1)				
Canada (770,000 Acres)	266	266	266	266
U.S. West (127,446 Acres)	387	387	387	387
U.S. Marcellus Shale (196,589 Acres)	565	565	565	565
Asset retirement obligations (2)	(238)	(129)	(29)	(10)
Long-term debt (net of cash)	(724)	(724)	(724)	(724)
Net working capital excluding deferred financial assets and credits and future income taxes	(207)	(207)	(207)	(207)
Marcellus carry commitment	(146)	(146)	(146)	(146)
Other equity investments (3)	155	155	155	155
Net Asset Value of Assets	**$11,280**	**$6,900**	**$5,057**	**$4,011**
Net Asset Value per Trust Unit(4)	**$63.14**	**$38.62**	**$28.31**	**$22.45**

(1) Acreage acquired in 2009 and 2010 valued at acquisition cost. Acreage acquired prior to 2009 valued at $100/acre.
(2) Asset retirement obligations ("ARO") do not equal the amount on the balance sheet ($208.7 million) as the balance sheet amount uses a 6.4% discount rate and a portion of the ARO costs are already reflected in the present value of reserves computed by the independent engineers.
(3) Other equity investment value based on cost, except value of Laricina equity valued based on last offering price of $30/share.
(4) Based on 178,648,000 Trust Units and equivalent Exchangeable Partnership Units outstanding as at December 31, 2010.

2011 OUTLOOK

2011 capital spending is anticipated to increase by 20% to $650 million with 65% projected to be invested in oil projects. We expect to focus approximately 85% of our spending on our Bakken, Waterflood and Marcellus resource plays. Approximately $420 million is planned for our oil projects with our Bakken portfolio attracting $300 million. With the current natural gas price outlook we plan to limit our spending on our natural gas assets in 2011 spending approximately $230 million, $160 million of which is planned for our Marcellus interests. The majority of the remainder of our natural gas spending is planned in the Deep Basin area where we hold approximately 80,000 net acres of land. We plan to drill up to four delineation wells targeting the Mannville in the South Ansell area where other producers have had recent success. Our shallow gas activities will consist only of recompletions at Shackleton targeting the multi-zone potential of the area. As a result of the decrease in spending in our tight and shallow gas resource plays, we expect production volumes from these plays will decline throughout 2011. We also expect a similar level and allocation of spending in 2012.

Given the longer lead time to production associated with a majority of our capital spending in the Marcellus and the Bakken, up to 40% of the production associated with our 2011 drilling program will not come on stream until the remaining completion and tie-in capital is spent in 2012. We plan to spend approximately $450 million on development drilling, recompletions and facilities, $140 million on delineation activities, $30 million on seismic and $30 million on maintenance activities. In total, approximately 113 net wells are planned, two thirds of which we would operate and 95% of which would be horizontal wells.

As a result of this spending, we expect annual 2011 production to average 78,000 – 80,000 BOE/day, essentially unchanged from exit 2010, and to increase to 80,000 – 84,000 BOE/day by year-end. Oil and liquids production is expected to grow 15% by year-end. Shallow gas and other conventional oil and gas production are expected to decline throughout the year due to reduced capital. Production is expected to grow by 10% - 15% over the next two years, exiting 2012 in the range of 86,000 - 90,000 BOE/day. Crude oil volumes are expected to increase approximately 20% over the next two years and crude oil and natural gas liquids are expected to represent just under 50% of total volumes by the end of 2012.

We do not have any specific plans to package and sell any significant producing non-core properties in 2011. As previously stated we expect to sell non-cash flow generating assets and may sell part of our non-operated Marcellus interests in 2012 in order to preserve our financial flexibility. As part of our original acquisition agreement, we expect to spend $116 million on our capital carry commitment associated with the Marcellus in 2011.

We expect our debt-to-cash flow ratio to increase to approximately 2.0 times in 2012 based upon the current forward commodity markets.

Key 2011 Capital Spending Plans & Estimated Production

Resource Play	**Capital ($MM)**	**# of net wells**	**2011E Exit Production**	**Exit to Exit Variance**
Bakken/Tight Oil (BOE/day)	300	48	18,000 - 21,000	35 – 55%
Waterfloods (BOE/day)	110	26	13,500 - 15,000	0 – 10%
Marcellus Shale Gas (Mcfe/day)	160	27	7,000 - 8,000	140 – 170%
Resource Play Total (BOE/day)	$570	101	38,500 – 44,000	30 - 45%
Total (BOE/day)	$650	113	80,000 – 84,000	5 – 10%

SUMMARY

We are positioning Enerplus to deliver competitive long-term returns that include a balance between growth and income to investors. We've made significant strides in repositioning our asset base and now have meaningful growth opportunities in our portfolio. We also have a strong foundation of cash generating assets combined with a strong balance sheet that will help support our growth and income strategy.

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

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Gordon J. Kerr
President & Chief Executive Officer
Enerplus Corporation

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. "MBOE" and "MMBOE" mean "thousand barrels of oil equivalent" and "million barrels of oil equivalent", respectively.

Presentation of Production and Reserves Information

*In accordance with Canadian practice, production volumes and revenues 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 National Instrument 51-101 adopted by the Canadian securities regulators ("**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, 2010, 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, 2010 ("**our AIF**") which will be available in mid-March 2011 on our website at www.enerplus.com and on our SEDAR profile at www.sedar.com. Additionally, the Annual Information*

Form 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 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." 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, 2010. 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 information regarding the primary contingencies which currently prevent the classification of our disclosed "contingent resources" associated with our Marcellus shale gas assets as reserves and the positive and negative factors relevant to the "contingent resource" estimate, see our Annual Information Form for the year ended December 31, 2009 (and corresponding Form 40-F) dated March 12, 2010, a copy of which is available on our SEDAR profile at www.sedar.com and a copy of the Form 40-F which is available on our EDGAR profile at www.sec.gov. With respect to the "contingent resource" estimate for our North Dakota Bakken properties, the primary contingencies which currently prevent the classification of our disclosed "contingent resources" associated with the properties as "reserves" consist of additional delineation drilling to establish economic productivity in the development areas and limitations to development based on adverse topography or other surface restrictions. Significant positive factors related to the estimate include; continued advancement of drilling and completion technology and early performance of producing wells that are above forecast. A significant negative factor related to the estimate is the limited performance history in the immediate area of the "contingent resource". There are a number of inherent risks and contingencies associated with the development of our interests in these properties including commodity price fluctuations, project costs, our ability to make the necessary capital expenditures to develop the properties, reliance on our industry partners in project development, acquisitions, funding and provisions of services and those other risks and contingencies described above, and that apply generally to oil and gas operations as described above, and under "Risk Factors" in our Annual Information Form referred to above.

F&D Costs and Recycle Ratio

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 will not reflect total finding and development costs related to its reserves additions for that year.

Recycle ratio is calculated by dividing operating netback per BOE (calculated by subtracting our royalties, state severance taxes and operating and gathering costs from its revenues) by the F&D cost per BOE.

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 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' strategy to deliver both income and growth to investors and Enerplus' related asset portfolio; future returns to shareholders from both dividends and from growth in per share production and reserves; future capital and development expenditures and the allocation thereof among our resource plays and assets; future development and drilling locations and plans; the performance of and future results from Enerplus' assets and operations, including anticipated production levels 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; securing necessary infrastructure and third party services; the amount of future asset retirement obligations; future cash flows and debt-to-cash flow levels; potential asset sales; returns on Enerplus' capital program; Enerplus' tax position; and future costs, expenses and royalty rates.*

The forward-looking information contained in this news release reflect 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 and cash flow 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 and 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 reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of adequate insurance coverage; the impact of competitors; reliance on industry partners; and 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 speak only as of the date of this news release, and none of Enerplus or its subsidiaries assumes 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 "recycle ratio" and "F&D costs" as measures of operating performance. We calculate "payout ratio" by dividing cash distributions to unitholders by cash flow from operating activities, both of which are measures prescribed by Canadian generally accepted accounting principles ("**GAAP**") and which appear on our consolidated statements of cash flow. "Adjusted payout ratio" is calculated as cash distributions to unitholders plus development capital and office expenditures, divided by cash flow from operating activities. "Recycle ratio" is calculated by dividing operating netback per BOE (calculated by subtracting Enerplus' royalties, state severance taxes and operating and gathering costs from its revenues) by the F&D cost per BOE. We also use the term "netback:", which is used to measure operating performance and is calculated by subtracting Enerplus' expected royalties and operating costs from the anticipated revenues in respect of the relevant properties.*

Enerplus believes that, in addition to net earnings and other measures prescribed by GAAP, the terms "payout ratio", "adjusted payout ratio", "recycle ratio", "F&D costs" and "netback" 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 GAAP. Therefore, these measures, as defined by Enerplus, may not be comparable to similar measures presented by other issuers.