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NEWS RELEASE

May 7, 2010

Enerplus reports first quarter results for 2010

CALGARY, May 7 /CNW/ - Enerplus Resources Fund ("Enerplus") (TSX - ERF.un, NYSE - ERF) is pleased to announce operating and financial results for the three months ended March 31, 2010. Full copies of our first quarter 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.

STRATEGIC EXECUTION:

- We continued to transition Enerplus into a growth and income oriented oil and gas producer by increasing our interests in early stage growth opportunities in the Marcellus shale gas play, the Deep Basin tight gas area and the Bakken oil play in both Canada and the U.S.

- We increased our acreage position in the Marcellus play and now hold approximately 136,000 net acres of land primarily in Pennsylvania and West Virginia. As part of our recent acquisitions, Enerplus has secured lands where we will act as operator. We expect to drill our first operated well toward the end of 2010. Results in this play to date are meeting our expectations with respect to production rates and assessments of contingent resources.

- In April we acquired 154 new sections (approximately 100,000 net acres) of undeveloped land in southern Saskatchewan at a Crown land sale for $117 million. These lands are in an emerging Bakken play area and are contiguous to our existing land holdings. We now hold a 100% working interest in approximately 142,000 acres in the Freda Lake/Neptune area and in aggregate over 170,000 net acres of undeveloped Bakken prospect lands in both Canada and the U.S.

- We increased our undeveloped land holdings in the Deep Basin area of western Canada where we now hold approximately 34,000 net acres of undeveloped land. Our primary focus in this area will be on the Montney and stacked zone potential in the Mannville. We have drilled two vertical wells on the lands and are currently evaluating these results.

- We are also continuing with our plans to divest of non-core conventional assets to improve the focus in our asset base. We still expect to realize a minimum of $200 million of proceeds in the current year through a partial sale of the 14,000 BOE/day of conventional assets identified as non-core in our portfolio.

- Our entire $1.4 billion syndicated bank facility was undrawn at the end of the quarter. Our balance sheet remains strong with a debt to trailing 12 month cash flow ratio of 0.7 times.

OPERATING PERFORMANCE:

- Daily production averaged 84,719 BOE/day during the quarter, on track with our expectations. Given the timing of our capital program, we expect our production will continue to increase throughout the year and meet our full year forecast of 86,000 BOE/day and our exit rate of 88,000 BOE/day, not including any acquisition or disposition activity that may occur throughout the year.

- Cash flow from operations was $1.07 per unit which was up over the first quarter of 2009 primarily due to the strength of crude oil prices. Approximately 51% of our cash flow was distributed to our unitholders through our monthly distributions of $0.18/unit through the quarter. When distributions are combined with capital spending during the quarter, our adjusted payout ratio was approximately 101% of cash flow.

- Development capital expenditures totaled $95.3 million during the quarter. We drilled 137.4 net wells with a drilling success rate of 100%.

- Operating costs of $9.96/BOE in the quarter were lower than our guidance of $10.90/BOE due primarily to the timing of annual maintenance activity expected in the second and third quarters. General and administrative costs of $2.56/BOE were also in line with our expectations.

SELECTED FINANCIAL RESULTS

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For the three months ended March 31,	2010	2009
Financial (000's)		
Cash Flow from Operating Activities	$189,357	$169,388
Cash Distributions to Unitholders(1)	95,712	89,537
Excess of Cash Flow Over Cash Distributions	93,645	79,851
Net Income	80,003	51,786
Debt Outstanding - net of cash	517,263	739,170
Development Capital Spending(2)	95,275	96,588
Property and Land Acquisitions(2)	41,327	4,632
Divestments	1,538	13
Actual Cash Distributions to Unitholders per Trust Unit	$0.54	$0.61
Financial per Weighted Average Trust Units(3)		
Cash Flow from Operating Activities	$1.07	$1.02
Cash Distributions(1)	0.54	0.54
Excess of Cash Flow Over Cash Distributions	0.53	0.48
Net Income	0.45	0.31
Payout Ratio(4)	51%	53%
Adjusted Payout Ratio(2)(4)	101%	110%
Selected Financial Results per BOE(5)		
Oil & Gas Sales(6)	$47.65	$35.24
Royalties	(8.57)	(6.43)
Commodity Derivative Instruments	0.51	5.38
Operating Costs	(9.91)	(9.95)
General and Administrative	(2.46)	(2.05)
Interest and Other Expenses	(0.86)	(0.91)
Taxes	-	(0.10)
Asset retirement obligations settled	(0.56)	(0.43)
Cash Flow from Operating Activities before changes in non-cash working capital	$25.80	$20.75
Weighted Average Number of Trust Units Outstanding(3)	177,169	165,716
Debt to Trailing 12 Month Cash Flow Ratio	0.7x	0.6x

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SELECTED OPERATING RESULTS

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For the three months ended March 31,	2010	2009
Average Daily Production		
Natural gas (Mcf/day)	298,920	338,857
Crude oil (bbls/day)	30,974	34,427
NGLs (bbls/day)	3,925	4,059
Total (BOE/day)	84,719	94,962
% Natural gas	59%	59%
Average Selling Price(6)		
Natural gas (per Mcf)	$5.10	$5.13
Crude oil (per bbl)	73.86	42.41
NGLs (per bbl)	57.47	40.59
CDN$/US$ exchange rate	0.96	0.80
Net Wells drilled	137	123
Success Rate(7)	100%	99%

(1) Calculated based on distributions paid or payable.
(2) Land acquisitions in prior periods have been reclassified from development capital expenditures to property acquisitions to conform with the current year presentation.
(3) Weighted average trust units outstanding for the period, includes the equivalent exchangeable limited partnership units.
(4) 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.

(5) Non-cash amounts have been excluded.

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

(7) Based on wells drilled, cased and tied in.

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TRUST UNIT TRADING SUMMARY

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For the three months ended March 31, 2010

	TSX - ERF.un (CDN$)	U.S.* - ERF (US$)
High	$24.96	$24.25
Low	$22.45	$20.85
Close	$24.07	$23.71

* U.S. Composite Exchange Data including NYSE.

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2010 CASH DISTRIBUTIONS PER TRUST UNIT

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Payment Month	CDN$	US$
January	$0.18	$0.17
February	0.18	0.17
March	0.18	0.18
First Quarter Total	$0.54	$0.52

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OPERATIONS

Approximately 56% of our capital was invested in crude oil related development projects during the quarter, primarily in our Bakken and crude oil waterflood plays. Our natural gas spending was concentrated in our Marcellus and tight gas plays, however, the majority of wells drilled during the quarter were located in our shallow gas resource play taking advantage of the Alberta Drilling Royalty Credit program ("DRC"). We continue to expect to invest approximately $425 million in our assets during 2010; however, we may reallocate capital to oil related projects as we assess opportunities in our growth plays.

PRODUCTION AND CAPITAL SPENDING SUMMARY

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For the three months ended March 31, 2010

Play Type	Average Production Volumes	Capital Spending ($ millions)
Bakken/Tight Oil (BOE/day)	8,833	30
Crude Oil Waterflood (BOE/day)	15,964	20
Conventional Oil (BOE/day)	10,132	3
Total Crude Oil (BOE/day)	34,929	$53
Shallow Gas (Mcfe/day)	126,451	7
Tight Gas (Mcfe/day)	89,766	15
Marcellus Shale Gas (Mcfe/day)	2,696	15
Conventional Gas (Mcfe/day)	79,827	5

Total Gas (Mcfe/day)	298,740	$42
Company Total (BOE/day)	84,719	$95*

* Net of $20 million in Alberta drilling royalty credits.

DRILLING ACTIVITY (NET WELLS)

For the three months ended March 31, 2010

Play Type	Horizontal Wells	Vertical Wells	Total Wells	Wells Pending Completion/ Tie-In	Wells On-stream	Dry & Abandoned Wells	Drilling Success Rate%
Bakken/Tight Oil	7.1	1.0	8.1	4.6	3.5	-	100%
Crude Oil Waterfloods	4.1	13.9	18.0	5.1	12.9	-	100%
Conventional Oil	1.5	0.8	2.3	2.3	-	-	pending
Total Oil	12.7	15.7	28.4	12.0	16.4	-	100%
Marcellus Shale Gas	2.7	-	2.7	2.7	-	-	pending
Shallow Gas	-	98.9	98.9	63.0	35.9	-	100%
Tight Gas	0.4	0.7	1.1	1.1	-	-	pending
Conventional Gas	-	6.3	6.3	3.0	3.3	-	100%
Total Gas	3.1	105.9	109.0	69.8	39.2	-	100%
Company Total	15.8	121.6	137.4	81.8	55.6	-	100%

MARCELLUS SHALE GAS

Activity in the Marcellus shale gas play in the U.S. continued throughout the first quarter despite record snowfall causing extremely wet surface conditions. A total of 12 gross wells were drilled during the quarter (2.7 net wells) across seven counties in Pennsylvania and we now have six rigs working in the play. Both completion activities and pipeline projects experienced delays in the quarter due to weather however activities are now back on track. Well costs continue to meet our expectations of approximately $4.5 million per well. Drilling days are trending lower than expected even though we are drilling longer horizontal legs with increased frac stages. Lateral lengths have ranged from 2,500 feet to 5,200 feet with 7 - 10 frac stages per well. We have drilled our first multi-well pad site with 5 wells and have recently completed 3 of these wells. Average 24-hour test rates of the last 10 wells drilled were 4.5 MMcf/day with the best well in the northeast development area testing at 8.2 MMcf/day and the best well in the southwest area testing at 7.1 MMcf/day. Marcellus production volumes for the quarter averaged 2.7 MMcf/day net to Enerplus and as of May 1 production had increased to approximately 6 MMcf/day net. We continue to expect our exit volumes will be in excess of 18 MMcf/day net. We currently have an approximate 20% working interest in 19 gross producing wells (15 horizontal wells and 4 vertical wells) and 39 gross wells awaiting tie-in and/or completion.

BAKKEN/TIGHT OIL

We continue to build momentum in our Bakken/tight oil resource play through the acquisition of approximately 108,000 net acres of undeveloped land year to date as well as successfully executing our capital program. Enerplus now holds over 170,000 net acres of undeveloped Bakken prospective lands in both Canada and the U.S. and we continue to look for additional opportunities to grow this land base on both sides of the border.

The southeast Saskatchewan Bakken play has become a meaningful new prospect area for Enerplus. In the last six months, we have drilled and completed 3 Bakken horizontal wells with multi-frac completions in the Freda/Neptune area. Preliminary test results are positive and we expect to contract two drilling rigs to further delineate and develop the play on these 100% operated lands. Given the similarity in well depths and reservoir quality to our joint-venture assets at Taylorton, we expect similar type curves for successful wells on these new lands. We believe the economics of

these wells will be attractive and expect that ultimately the play could be developed on the basis of up to four horizontal wells per section on a risked basis.

At Fort Berthold, North Dakota, we participated in the drilling of 3 horizontal wells (2 with a 50% working interest) during the quarter and currently have 2 wells completed and producing. The average lateral length of these wells ranged from 4,000 feet to 4,300 feet with 12 stage completions and 24-hour initial test rates have averaged approximately 1,100 BOE/day per well. We expect to have 3 to 6 more wells completed by the end of the second quarter. Given the success in this area, we expect that we may direct more of our 2010 development capital spending to the Fort Berthold area.

At Sleeping Giant, Montana, we drilled a total of 5 gross wells (3.5 net to Enerplus) which have been completed using multi-stage fracturing technology. As of May 1, all of these wells were on stream. Production rates on these wells are encouraging and we are evaluating results in conjunction with an analysis of the entire Sleeping Giant field. While we still expect to drill an additional 4 operated wells and 2 non-operated wells at Sleeping Giant during the balance of the year, we will be evaluating these plans in relation to our field analysis work and our other development opportunities including refracs.

CORPORATE CONVERSION

As a result of the Canadian federal government's tax on trusts, we anticipate converting to a dividend paying corporation effective January 1, 2011. While our cash flows and the amount we distribute to unitholders will vary depending on commodity prices, production volumes and costs, we do not expect to adjust our monthly cash distributions solely as a result of our conversion to a corporation. We have approximately $3 billion in tax pools that can be used to provide shelter from cash taxes in Canada for three to five years beyond 2010 (depending on commodity prices, production volumes, capital spending and any acquisition and divestment activity we may transact) and expect to be taxable at an estimated rate of 10-15% following this period. Subject to the approval of our corporate conversion plan by the Board of Directors, we expect to proceed with a Special Meeting of Unitholders in December of this year and ultimately convert to a corporation on or about January 1, 2011.

We remain committed to providing investors with a superior investment within the oil and gas industry and believe that a business strategy that offers both growth and income can achieve this. We expect to continue to improve our asset base through the addition of earlier stage growth oriented assets to our portfolio and by divesting of non-core conventional properties. We believe this will create a stronger mix of assets that will improve our operating results and create value for our investors in both the near term and the future.

CONSOLIDATED FINANCIAL STATEMENTS AND MD&A

First quarter 2010 Consolidated Financial Statements and Notes to the Consolidated Financial Statements, along with the Management's Discussion and Analysis for Enerplus have been filed on our website at www.enerplus.com, under our profile on SEDAR (www.sedar.com) and on the EDGAR website at www.sec.gov.

INFORMATION REGARDING DISCLOSURE IN THIS NEWS RELEASE

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

Where applicable, natural gas has been converted to barrels of oil equivalent ("BOE") based on 6 Mcf:1 BOE. The BOE rate is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalent at the wellhead. Use of BOE in isolation may be misleading. "MMcfe" means million cubic feet of gas equivalent. Enerplus has adopted the standard of one barrel of oil to six thousand cubic feet of gas (1 barrel: 6 Mcf) when converting oil to MMcfes. MMcfes may be misleading, particularly if used in isolation. An MMcfe conversion ratio of 1 barrel: 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

In accordance with Canadian practice, production volumes and revenues are reported on a gross basis, before deduction of Crown and other royalties, unless otherwise stated.

FORWARD-LOOKING INFORMATION AND STATEMENTS

This news release contains certain forward-looking information and statements 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" and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the foregoing, this news release contains forward-looking information and statements pertaining to the following: the amount, timing and tax treatment of cash distributions to unitholders; payout ratios and adjusted payout ratios; tax treatment of income trusts such as the Fund; the structure of the Fund and its subsidiaries including conversion to a corporate structure; the Fund's income taxes, tax liabilities and tax pools; the volume and product mix of the Fund's oil and gas production; production and operational matters including drilling plans and delayed projects; oil and natural gas prices and the Fund's risk management programs; the amount of asset retirement obligations; future liquidity and financial capacity and resources; future capital expenditures; cost and expense estimates; results from operations and financial ratios; the impact of the conversion to IFRS on the financial results of the Fund; the Fund's ongoing strategy; the Fund's credit exposure; cash flow sensitivities; royalty rates and their impact on the Fund's operations and results; future growth

including development, exploration, and acquisition and development activities and related expenditures; and future dispositions of oil and gas assets. This press release also contains estimates of contingent resources, which are by their nature estimates that the quantities described exist in the amounts estimated.

The forward-looking information and statements contained in this news release reflect several material factors and expectations and assumptions of the Fund including, without limitation: that the Fund will continue to conduct its operations in a manner consistent with past operations; the general continuance of current or, where applicable, assumed industry conditions and tax and regulatory regimes; availability of cash flow, debt and/or equity sources to fund the Fund's capital and operating requirements as needed; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; the accuracy of the estimates of the Fund's reserve and resource volumes; and certain commodity price and other cost assumptions. The Fund believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable at this time but no assurance can be given that these factors, expectations and assumptions will prove to be correct.

The forward-looking information and statements included in this news release are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve 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 or statements including, without limitation: changes in commodity prices; unanticipated operating results or production declines; changes in tax or environmental laws or royalty rates; increased debt levels or debt service requirements; inaccurate estimation of the Fund's oil and gas reserves and resources volumes; limited, unfavourable or no access to debt or equity capital markets; increased costs and expenses; the impact of competitors; reliance on industry partners; and certain other risks detailed from time to time in the Fund's public disclosure documents including, without limitation, those risks identified in the MD&A, our MD&A for the year ended December 31, 2009 and in the Fund's Annual Information Form for the year ended December 31, 2009, copies of which are available on the Fund's SEDAR profile atwww.sedar.com and which also form part of the Fund's Form 40-F for the year ended December 31, 2009 filed with the SEC, a copy of which is available at www.sec.gov.

The forward-looking information and statements contained in this news release speak only as of the date of this release and none of the Fund 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.

INFORMATION REGARDING 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 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 it will be commercially viable to produce any portion of the contingent resources or that Enerplus will produce any portion of the volumes currently classified as contingent resources. The resource estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources may be greater than or less than the estimates provided herein.

The primary contingencies which currently prevent the classification of Enerplus' disclosed contingent resources associated with the Marcellus properties as "reserves" consist of: additional delineation drilling to establish economic productivity in the development areas, limitations to development based on adverse topography or other surface restrictions, the uncertainty regarding marketing and transportation of natural gas from development areas, the receipt of all required regulatory permits and approvals to develop the lands, and access to confidential information of other operators in the area. Significant negative factors related to the estimate include: the pace of development, including drilling and infrastructure, is slower than the forecast, risk of adverse regulatory and tax changes, ongoing litigation related to minimum royalties payable to freehold landowners, and other issues related to oil and gas development in populated areas. There are a number of inherent risks and contingencies associated with the development of the acquired interests in the Marcellus properties, including commodity price fluctuations, project costs, Enerplus' ability to make the necessary capital expenditures to develop the properties, reliance on Enerplus' 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 under "Risk Factors" in our annual information form for the year ended December 31, 2009, a copy of which is available on our SEDAR profile atwww.sedar.com and on our website at www.enerplus.com, and which forms part of our annual report on Form 40-F filed with the U.S. Securities and Exchange Commission at www.sec.gov.

NON-GAAP MEASURES

Throughout this news release we use the term "payout ratio" and "adjusted payout ratio" to analyze operating performance, leverage and liquidity. We calculate payout ratio by dividing cash distributions to unitholders ("cash distributions") by cash flow from operating activities ("cash flow"), both of which appear on our consolidated statements of cash flows. "Adjusted payout ratio" is calculated as cash distributions plus development capital and office expenditures divided by cash flow. The terms "payout ratio" and "adjusted payout ratio" do not have a standardized meaning or definition as prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other entities. Refer to the Liquidity and Capital Resources section of the MD&A for further information.

Gordon J. Kerr

President & Chief Executive Officer
Enerplus Resources Fund

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