ENERPLUS RESOURCES FUND
Form 6-K
November 15, 2002

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SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 6-K

Report of Foreign Issuer pursuant to Rule 13-a-16 or 15d-16
of the Securities Exchange Act of 1934

FOR THE MONTH OF NOVEMBER, 2002

COMMISSION FILE NUMBER 1-15150

The Dome Tower
Suite 3000, 333 - 7th Avenue S.W.
Calgary, Alberta
Canada T2P 2Z1
(403) 298-2200

Indicate by check mark whether the registrant files or will file annual reports under cover Form 20-F or Form 40-F.

Form 20-F o Form 40-F ý

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1)

Yes o No ý

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Yes o No ý

Indicate by check mark whether, by furnishing the information contained in this Form, the registrant is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the securities Exchange Act of 1934.

Yes o No ý

EXHIBIT INDEX

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EXHIBIT 1

FOR IMMEDIATE RELEASE

EXHIBIT 1: 3RD QUARTERLY REPORT TO UNITHOLDERS, INCLUDING THE INTERIM MANAGEMENT'S DISCUSSION AND ANALYSIS AND FINANCIAL STATEMENTS FOR THE NINE MONTHS PERIOD ENDED SEPTEMBER 30, 2002.

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ENERPLUS RESOURCES FUND

THIRD QUARTER REPORT FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2002
2002 SELECTED COMBINED FINANCIAL AND OPERATING RESULTS

For the nine months ended September 30,	**2002**	**2001(1)**
OPERATING		
Average Daily Volumes:		
Natural gas (Mcf/day)	**204,463**	203,478
Crude oil (bbls/day)	**23,117**	24,330
NGLs (bbls/day)	**4,299**	4,777
Total (BOE/day) (6:1)	**61,493**	63,020
% Natural gas	**55%**	54%
Reserve life index (years)(3)	**14.0**	13.7

	CDN$				US$(2)			
For the nine months ended September 30,		**2002**		**2001(1)**		**2002**		**2001(1)**
Average Selling Price Pre-Hedging								
Natural gas (per Mcf)	**$**	**3.44**	$	5.97	**$**	**2.19**	$	3.88
Crude oil (per bbl)		**33.69**		34.08		**21.46**		22.16
NGLs (per bbl)		**23.06**		35.36		**14.69**		22.99
Currency exchange rate (CDN$ to US$)	**$**	**0.6369**	$	0.6502	**$**	**0.6369**	$	0.6502
FINANCIAL (combined basis, Unaudited) ($000)								
Oil and gas sales before Hedging	**$**	**431,353**	$	603,976	**$**	**274,730**	$	392,705
Proceeds (cost) of hedging		**(2,945)**		10,787		**(1,876)**		7,014

	CDN$		US$(2)	
Royalties	**88,515**	141,668	**56,376**	92,112
Operating costs	**95,853**	99,293	**61,049**	64,560
Operating netback	**244,040**	373,802	**155,429**	243,047
General and administrative	**10,085**	8,336	**6,422**	5,420
Management fees	**13,571**	9,700	**8,644**	6,307
Interest expense, net	**12,367**	15,333	**7,877**	9,970
Capital taxes	**3,950**	4,150	**2,516**	2,698
Site restoration and Abandonment	**3,130**	1,976	**1,993**	1,285
Funds flow from operations	**200,937**	334,307	**127,977**	217,367
Cash withheld for debt Reduction	**$ 33,920**	$ 40,424	**$ 21,604**	$ 26,284

(1) The 2001 operating and financial information reflects the combined results of Enerplus and EnerMark as if the Merger had been effective January 1, 2001. Combined information provides a historical perspective of the capabilities of the combined entity. This information is also relevant as both Enerplus Resources Fund and EnerMark Income Fund have been managed by the same management group since inception. **This information is unaudited and does not conform to Canadian Generally Accepted Accounting Principles.**

(2) All US$ amounts shown in the table above were converted using the Canadian to U.S. dollar exchange rate for the applicable periods as indicated within the table.

(3) Calculated at December 31 of prior year.

MESSAGE TO UNITHOLDERS

I am pleased to report that Enerplus continued to deliver results in line with our objectives during the third quarter of 2002. Production volumes for the nine month period of 61,493 BOE/day are on target and general and administrative expenses and operating costs continue to be in line with our expectations for the year. A considerable decrease in natural gas prices during the period compared to the previous quarter was partially offset by strengthening crude oil prices as well as the Fund's physical and financial natural gas contracts. Monthly cash distributions to Unitholders were increased by 7% to $0.30 per unit for the months of October and November resulting in total year-to-date distributions paid of $2.40 per unit. In addition, $0.48 per trust unit has been withheld for debt repayment representing a payout ratio of 83%.

On September 12, 2002, Enerplus successfully closed a Canadian equity offering, raising gross proceeds of $127.5 million. This helped to strengthen our balance sheet and replenish credit facilities that were employed to fund development and acquisition activities. During the quarter, over $44 million was invested in the Fund's existing asset base to increase production levels and improve operating efficiencies. Our low-risk exploitation activities resulted in over 135 gross developmental wells drilled with a 99% success rate. In addition, the Fund acquired a 16% working interest in Athabasca Oil Sands Lease #24. This strategic investment in the Canadian oil sands area of Alberta provides the Fund with an entry into this world-class, long reserve life asset. Over the long-term, this investment is expected to provide Enerplus Unitholders with exposure to significant low-cost reserves and stable production growth. Subsequent to the end of the quarter, Enerplus concluded the acquisition of Celsius Energy Resources Ltd. adding approximately 5,700 BOE/day of daily production and approximately 18 MMBOE of established reserves to the Fund. With this acquisition, Enerplus has invested approximately $215 million year-to-date in acquiring high quality oil and natural gas assets and has effectively replaced the Fund's production for 2002.

At this time, I wish to acknowledge the contribution of Mr. Arne Nielsen who has resigned his position with the Board of Directors. Mr. Nielsen has been a director of Enerplus and its predecessors since May of 1994 and has been a valuable contributor to the growth and success of the Fund over the years. We thank him for his contributions and wise counsel and wish him all the best for the future.

Gordon J. Kerr

President & Chief Executive Officer

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2002 CASH DISTRIBUTIONS PER TRUST UNIT

Production Month	Payment Month	CDN$	US$
January	March	$ 0.20	$ 0.13
February	April	0.20	0.13
March	May	0.28	0.18
First Quarter total		**$ 0.68**	**$ 0.44**
April	June	0.28	0.18
May	July	0.28	0.18
June	August	0.28	0.18
Second Quarter total		**$ 0.84**	**$ 0.54**
July	September	0.28	0.18
August	October	0.30	0.19
September	November	0.30	0.19*
Third Quarter total		**$ 0.88**	**$ 0.56**
Year-to-Date Total		**$ 2.40**	**$ 1.54**

* Using an estimated Canadian/US dollar exchange rate of 1.57

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TRUST UNIT TRADING SUMMARY

Three months ended September 30, 2002	Toronto Stock Exchange ERF.un (CDN$)	New York Stock Exchange ERF (US$)
High	$29.00	$19.08
Low	$24.26	$14.94
Close	$28.50	$17.87
Volume	9,818,554	9,752,600

DEVELOPMENT ACTIVITIES

During the third quarter, Enerplus continued with its capital development activities focusing primarily on the shallow gas developmental drilling program that was initiated in the second quarter. A total of $44.8 million was invested with 135 gross wells drilled, 124 of which were natural gas wells. Year-to-date, a total of 226 gross wells have been drilled and completed with a 99% success rate. Much of the development capital spent in the third quarter should translate into production gains in the fourth quarter as Enerplus moves quickly to tie-in these new wells.

2002 Third Quarter Drilling Activity

Drilling Activity	Crude Oil Wells		Natural Gas Wells		Dry & Abandoned Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net

					Dry & Abandoned Wells			
Alberta	9.0	4.3	99.0	86.6	1.0	1.0	109.0	91.9
Saskatchewan	1.0	1.0	25.0	24.2			26.0	25.2
Total	10.0	5.3	124.0	110.8	1.0	1.0	135.0	117.1
Year-to-Date Total	44.0	20.8	179.0	158.6	3.0	1.6	226.0	181.0

Success Rate: 99%

Hanna/Garden Plains, Alberta (Operated, W.I. 91%)

At Hanna/Garden Plains, 18 of the 24 natural gas development wells drilled in the second quarter were brought on-stream in July. In order to further optimize the natural gas production, coil tubing strings were inserted into these new wells which produce from the Second White Specks formation. As a result of these activities, incremental production volumes of approximately 900 Mcf/day net to the Fund of sweet natural gas have been added. Late in the third quarter, a second phase of development drilling was initiated, with a total of 31 wells drilled by the end of the quarter. These wells will be tied-in along with the remaining phase one wells in the fourth quarter. In total, Enerplus invested approximately $5.2 million in development capital in the Hanna/Garden Plains areas in the third quarter. The Hanna property produced an average of 12.4 MMcf/day of natural gas net to the Fund during the period.

Medicine Hat North, Alberta (Operated, W.I. 100%)

A 50 well natural gas developmental drilling program that was initiated in the second quarter of 2002 at Medicine Hat North was completed during the third quarter. As a result of this activity, additional compression capacity was installed in August to handle the new natural gas production volumes attributable to this program. At September 30th, a total of 44 wells had been tied-in resulting in incremental production volumes of approximately two million cubic feet of natural gas per day. Coiled tubing strings will be run in the wells in early October to further maximize production. Enerplus

invested $6.9 million in developing the Medicine Hat North property in the third quarter. Daily production volumes from the property averaged 2.4 MMcf/day of natural gas during the period.

Medicine Hat Sun Valley, Alberta (Operated, W.I. 100%)

At Medicine Hat Sun Valley, a 30 well developmental drilling program was completed during the third quarter along with the installation of a gathering system. Incremental gas volumes of approximately 1.5 MMcf/day are anticipated to be on stream in the fourth quarter. A total of $2.8 million was invested in this property during the third quarter and it produced an average of 6.9 MMcf/day of natural gas.

Joarcam, Alberta (Operated W.I. 80%)

Three additional Viking oil wells drilled late in the quarter are expected to be on stream during the fourth quarter. Infrastructure upgrades and facility expansions concluded in the second quarter have ensured that incremental production from this drilling activity will be readily handled. Natural gas production from this property was down 43.8% for the third quarter due to reservoir and facility maintenance but has returned to normal levels for the fourth quarter. Enerplus is currently reviewing the results of its capital expenditure activities to date at Joarcam to determine additional recompletion and workover projects. No further drilling activity is planned for the fourth quarter of 2002.

Gleneath Unit, Saskatchewan (Operated, W.I. 81%)

Enerplus continued with its capital expenditures program at Gleneath throughout the third quarter of 2002. The primary focus of this year's program was to improve production levels through low-cost fracture stimulation techniques. The program has been successful with a total of 49 wells completed year to date including 12 re-fracs in the third quarter. Average incremental production volumes from this re-stimulation activity are approximately 340 BOE/day consisting primarily of light sweet crude. Enerplus has scheduled seven additional re-stimulations for the fourth quarter of 2002 to complete this program and is on target to initiate a nine-well infill drilling program during the fourth quarter as well. Production from the Gleneath unit averaged 1,180 BOE/day net to Enerplus during the third quarter.

ACQUISITIONS

Year-to-date, Enerplus has invested approximately $215 million to acquire over 26 MMBOE of established reserves and daily production volumes of approximately 7,100 BOE per day. These transactions more than replace the Fund's anticipated production volumes this year.

During the third quarter of 2002, Enerplus acquired a 16% working interest in Oil Sands Lease #24 (also known as the Joslyn Creek Lease) for $16.4 million. Oil Sands Lease #24 is a 50,000-acre lease situated approximately 40 miles northwest of Fort McMurray strategically situated in the Athabasca Oil Sands fairway of central Alberta, adjacent to the MicMac oil sands mine and the Syncrude mine. Enerplus believes the long-term strategic nature of this investment provides an ideal entry into the development of the Athabasca Oil Sands a key driver in the future of the Western Canadian Sedimentary Basin. Initial assessment work for a steam assisted gravity drainage ("SAGD") project has been completed on the lease, including the drilling of 230 core hole wells, a third party independent engineering assessment, and the completion of a successful SAGD pilot project. The next phase of the project will consist of a 2,000 barrel of oil per day commercial SAGD development, which is scheduled to begin in early 2003. Oil production from this next phase is expected to commence in 2004. A full-scale commercial 30,000 bbl/day SAGD project is expected to follow, with oil production on stream by 2008. The potential for a second 30,000 bbl/day project also exists on the lease. Enerplus' net capital expenditure commitments for the 2,000 bbl/day project are estimated to be $11.5 million over the next 2 years. Enerplus has the option to participate in further development of the oil sands lease, subject to

non-participation provisions, but is under no obligation to do so. Once fully developed, the SAGD projects are expected to have an established Reserve Life Index in excess of 25 years. The recoverable reserves associated with one 30,000 bbl/day SAGD development on the Oil Sands Lease #24 are estimated to be 275 million barrels of oil (44 million barrels net to Enerplus). In keeping with current industry practices, Enerplus expects to record reserves as the Oil Sands Lease #24 is developed over time.

Subsequent to the end of the third quarter, Enerplus purchased Celsius Energy Resources Ltd., a private oil and natural gas producer for $166 million inclusive of working capital adjustments. Celsius' assets are primarily located in Alberta and northeastern British Columbia and provide excellent synergy with Enerplus' existing assets, particularly in the Verger, Countess, Pine Creek and Deep Basin areas. Included in the acquisition are approximately 103,000 net acres of undeveloped land plus seismic data that will provide further development opportunities to the Fund through potential farm-out and swap arrangements. Enerplus has identified over 300 low-risk development drilling locations within the Celsius properties. Capital expenditures for 2003 on the properties are estimated at approximately $17 million. Enerplus acquired daily production volumes of 5,750 BOE/day and 18 MMBOE of established reserves.

MARKETING

NATURAL GAS

After experiencing high prices during the second quarter of 2002, Canadian natural gas prices responded to decreased summer demand and started the third quarter of 2002 at prices as low as CDN$1.60/Mcf. By the end of the third quarter, natural gas prices began to strengthen in response to high crude oil prices. A late summer heat wave, an active storm season in the gulf coast, and questions concerning declining drilling activity and supply, served to push natural gas prices to levels in excess of CDN$5.00/Mcf as the fourth quarter commenced.

Capacity constraints caused by temporary operational maintenance programs on a few of the export pipelines combined with additional US supply created a situation where the difference between the NYMEX Henry Hub ("HH") price and the Canadian AECO price widened considerably to the detriment of Enerplus' Alberta-based natural gas prices. The NYMEX HH price for the third quarter averaged US$3.10/Mcf down only 6% from the previous quarter, while the AECO price averaging CDN$3.25/Mcf, was down 26% from the second quarter.

Near term, future natural gas prices are primarily dependent on winter weather conditions. Over the mid to longer term, supply will be affected by the constraints caused by reduced drilling activity, lower capital investment and a lack of exploration success while the demand for natural gas will be dependent upon the timing of an economic recovery in the U.S.

CRUDE OIL

The price of West Texas Intermediate crude oil ("WTI") continued to climb from the lows experienced at the beginning of 2002 to average US$28.27/bbl during the third quarter. This reflects an 8% increase over the previous quarter and brings the nine month average WTI price to US$25.40/bbl. Despite this increase, the year-to-date average price remains lower than the WTI price of US$27.81/bbl realized for the same period in 2001. Near term prices continue to be supported by the continued political tension in the Middle East, while longer term prices appear be more dependent on the actual balance between supply and demand. The price discounts applied to the Fund's heavier crude oil streams lessened during the summer months due to increased demand for asphalt combined with the increased WTI price. As a result, the Fund's heavy oil netbacks improved during this period. Continued weakness in the Canadian dollar benefited the Fund's crude oil revenues as the majority of Canada's crude oil is exported and referenced to US dollar denominated price benchmarks.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

The following discussion and analysis of the financial results of Enerplus Resources Fund ("Enerplus" or the "Fund") should be read in conjunction with:

- the MD&A and Audited Consolidated Financial Statements as at and for the years ended December 31, 2001 and 2000; and
- the Interim Unaudited Consolidated Financial Statements as at and for the three and nine months ended September 30, 2002 and 2001.

All amounts 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. In accordance with Canadian practice, production volumes, reserve volumes and revenues are reported on a gross basis, (before crown and freehold royalties), unless otherwise indicated.

Third Quarter 2002 Highlights

- The Fund paid $0.88 per trust unit ($64.5 million) in cash distributions to Unitholders with respect to the quarter and retained $0.05 per trust unit ($3.9 million) to reduce debt incurred on acquisition and development spending.
- On August 8, 2002, Enerplus acquired a 16% working interest in Oil Sands Lease #24 (also known as the Joslyn Creek Lease) for $16.4 million and the assumption of $4.1 million in contingent project debt.
- On September 12, 2002, the Fund successfully closed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127.5 million.
- The Fund experienced lower prices for its natural gas and NGLs in the third quarter of 2002 when compared to the third quarter of 2001. Both natural gas and NGL prices declined 2% during this time period. These price declines were offset by a 7% increase in the price of crude oil over the same period.
- Operating costs of $6.21/BOE for the three months ended September 30, 2002 were slightly lower than the same period in 2001 of $6.25/BOE. During the nine months ended 2002, operating costs continued to be in line with prior periods with operating costs decreasing slightly to $5.71/BOE from $5.77/BOE during the comparable period in 2001.
- Enerplus continued with its active development program, investing $44.8 million in development drilling and facility enhancements for the three months ended September 30, 2002. During the quarter, Enerplus drilled 135 gross wells (117.1 net wells) with a 99% success rate.
- Subsequent to the end of the third quarter, Enerplus completed the acquisition of Celsius Energy Resources Ltd. for $165.9 million inclusive of working capital adjustments. The Fund acquired daily production volumes of 5,750 BOE/day and 18 MMBOE of established reserves.

Important Information Regarding Comparative Financial Statements

On June 21, 2001, the respective Unitholders of EnerMark Income Fund ("EnerMark") and Enerplus Resources Fund overwhelmingly approved a merger combining the two funds (the "Merger"). As the former Unitholders of EnerMark held approximately 69% of the outstanding trust units of the combined fund at the date of acquisition, the Merger was accounted for using the reverse takeover form of the purchase method of accounting for business combinations. For accounting purposes, EnerMark acquired Enerplus effective June 21, 2001 and continues as Enerplus Resources Fund which has a 16-year history, market recognition and a listing on the New York Stock Exchange.

With the reverse takeover form of the purchase method of accounting, the unaudited consolidated financial statements presented herein include the accounts of EnerMark and Enerplus as at and for the three and nine months ended September 30, 2002. The historical comparative financial information for the year 2001 presented in the interim unaudited consolidated financial statements includes the results of EnerMark for the entire period, and only the results of Enerplus for the period from the date of the Merger to September 30, 2001.

RESULTS OF OPERATIONS

Production

Daily production averaged 60,730 BOE/day during the three months ended September 30, 2002, representing a 1% increase over production volumes of 60,331 BOE/day for the same period in 2001. Production remained relatively consistent over the periods as natural reservoir declines were more than offset by production gains from acquisition and development activity. This was particularly evident for crude oil as the volumes increased 5% or 1,092 bbls/day for the three months ended September 30, 2002 compared to 2001. The majority of this increase can be attributed to the property acquisition in the Medicine Hat Glauconite "C" area during the first quarter of 2002. Natural gas production during the third quarter of 2002 was lower compared to the three months ended June 30, 2002 due to plant turnarounds and maintenance.

Production for the nine months ended September 30, 2002 increased 19% to 61,493 BOE/day compared to the corresponding period in 2001. This increase is attributable to the Merger that occurred on June 21, 2001. The nine month comparison of 2001 production reflects the volumes of the predecessor Enerplus Resources Fund only from the date of the Merger.

Enerplus expects production levels to increase in the fourth quarter as a result of the Celsius acquisition combined with incremental production gains as wells drilled in the third quarter are brought on stream. Production from the Celsius acquisition is not recorded in the third quarter as the transaction closed October 21, 2002 and production from the newly acquired Oil Sands Lease #24 is not expected until 2004.

Enerplus' average production portfolio for the three months ended September 30, 2002 was weighted 54% natural gas, 39% crude oil, and 7% natural gas liquids on a per BOE basis. Average production volumes are outlined as follows:

	Three Months ended September 30,			Nine Months ended September 30,		
	2002	**2001**	**% Change**	**2002**	**2001**	**% Change**
Daily Sales Volumes						
Natural gas (Mcf/day)	198,452	199,823	(1%)	204,463	167,304	22%
Crude oil (bbls/day)	23,560	22,468	5%	23,117	19,760	17%
NGLs (bbls/day)	4,095	4,559	(10%)	4,299	3,879	11%
Total daily sales (BOE/day)	60,730	60,331	1%	61,493	51,523	19%

Pricing and Price Risk Management

Although the AECO monthly index price decreased 17% from $3.92/Mcf in 2001 to $3.25/Mcf in 2002, the Fund experienced only a 2% decline in the average price (before hedging) received on natural gas from $3.43/Mcf for the three months ended September 30, 2001 to $3.37/Mcf for the same period in 2002. Enerplus was able to moderate the decline in the AECO index through the benefit of a number of fixed price natural gas delivery contracts. For the nine months ended September 30, 2002, Enerplus' natural gas prices (before hedging) decreased 39% from the comparable period 2001. This decline is consistent with the sharp reduction in the AECO and NYMEX price indices from the peak experienced during the first half of 2001.

The average price that Enerplus received for its crude oil (before hedging) increased 7% from CDN$35.11/bbl for the third quarter of 2001 to CDN$37.41/bbl in the same quarter in 2002, which corresponds with the increase in the price of benchmark West Texas Intermediate (WTI) crude oil after adjusting for the change in the US$ exchange rate. For the nine months ended September 30, 2002 the average price received for crude oil (before hedging) decreased 1% from the comparable period in 2001, lower than the 9% decrease in price of the WTI crude oil. This difference is mainly due to the different product mix recognized in 2002 as a result of the Merger.

The realized prices for natural gas liquids ("NGLs") decreased 2% from the third quarter of 2001 to average $25.81/bbl for the third quarter of 2002. For the nine months ended September 30, 2002, NGL prices decreased 34% from the comparable period in 2001. In both the three and nine month comparisons, the realized prices for NGLs were influenced by the corresponding prices for natural gas.

	Three Months ended September 30,			Nine Months ended September 30,		
	2002	**2001**	**% Change**	**2002**	**2001**	**% Change**
Average Selling Price (before hedging)						
Natural gas (per Mcf)	$ 3.37	$ 3.43	(2%)	$ 3.44	$ 5.68	(39%)
Crude oil (per bbl)	$ 37.41	$ 35.11	7%	$ 33.69	$ 33.93	(1%)
NGLs (per bbl)	$ 25.81	$ 26.29	(2%)	$ 23.06	$ 34.79	(34%)
Total daily sales (per BOE)	$ 27.24	$ 26.38	3%	$ 25.69	$ 34.08	(25%)

	Three Months ended September 30,			Nine Months ended September 30,		
	2002	**2001**	**% Change**	**2002**	**2001**	**% Change**
Benchmark Pricing						
AECO (30 day) natural gas (per Mcf)	$ 3.25	$ 3.92	(17%)	$ 3.67	$ 7.30	(50%)
NYMEX natural gas (US$ per Mcf)	$ 3.26	$ 2.98	9%	$ 3.01	$ 5.01	(40%)
WTI crude oil (US$ per bbl)	$ 28.27	$ 26.76	6%	$ 25.39	$ 27.82	(9%)
Currency $1 CDN in US $	$ 0.6398	$ 0.6472	(1%)	$ 0.6369	$ 0.6502	(2%)

Enerplus has continued to implement hedging transactions in accordance with its commodity price risk management program during the third quarter. The program is intended to provide a measure of stability to the Fund's cash distributions as well as ensure Enerplus realizes positive economic returns from its capital development and acquisition activities. Enerplus' commodity risk management program is described in detail in Note 5 to the interim consolidated financial statements. Enerplus has the following physical and financial contracts in place:

Physical & Financial	**Contracted Gas volumes (MMcf/day)**	**% of estimated gross gas production***	**Contracted Oil volumes bbls/day**	**% of estimated gross oil production***
Remainder 2002	66.0	29%	11,175	45%
2003	75.0	33%	11,000	44%
2004	44.0	19%	6,500	26%

* Production volumes measured with reference to year-to-date production adjusted for the Celsius acquisition.

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For the three months ended September 30, 2002, Enerplus realized a hedging gain of $0.8 million on natural gas and a hedging loss of $1.7 million on crude oil as a result of its price risk management program. This realized loss is mainly due to an improvement in the markets for crude oil while the realized gain was due to a decrease in natural gas prices during the quarter. For the nine months ended September 30, 2002, Enerplus has realized a hedging loss on both natural gas and crude oil of $0.5 million and $2.4 million respectively. For the comparable period in 2001, Enerplus realized a $3.1 million hedging loss on crude oil and a $16.2 million hedging gain on natural gas. The mark-to-market value of

Enerplus' forward commodity price contracts at September 30, 2002 represented an unrealized loss of $18.0 million for natural gas and an unrealized loss of $9.0 million for crude oil. In other words, if Enerplus was to settle its forward commodity price contracts at September 30, 2002 with reference to the forward market at that time, it would have to make a payment of approximately $27.0 million. The mark-to-market loss has widened from the second quarter because the forward prices for crude oil and natural gas had strengthened by September 30, 2002.

OIL AND GAS SALES

Crude oil and natural gas revenues, including net hedging costs, were $151.3 million for the three months ended September 30, 2002, which was 8% lower than the $163.8 million reported for the same period in 2001. The decreased revenue was primarily due to a gain of $18.9 million realized in 2001 on natural gas hedging contracts. For the nine months ended September 30, 2002, crude oil and natural gas revenues, including net hedging costs, were $428.4 million compared to $492.4 million for the comparable period in 2001.

ANALYSIS OF SALES REVENUES ($ millions)

	Crude Oil	NGLs	Natural Gas	Total
2001 3rd Quarter Revenues	$ 71.0	$ 11.0	$ 81.8	$ 163.8
Price variance	5.0	(0.2)	(1.1)	3.7
Volume variance	3.6	(1.1)	(0.4)	2.1
Hedging cost variance	(0.2)		(18.1)	(18.3)
2002 3rd Quarter Revenues	$ 79.4	$ 9.7	$ 62.2	$ 151.3

Royalties

Royalties decreased from $32.9 million or 20% of oil and gas sales for the three months ended September 30, 2001 to $29.0 million or 19% for the three months ended September 30, 2002. For the nine months ended September 30, 2002 royalties decreased from $115.6 million or 23% of oil and gas sales in 2001 to $88.5 million or 21% of oil and gas sales. In the three and nine month comparisons, the decline in royalties as a percentage of oil and gas sales is attributable to a lower reference natural gas price used to calculate crown royalties during 2002.

Operating Expenses

Operating expenses totaled $34.7 million or $6.21/BOE for the three months ended September 30, 2002 compared to $34.7 million or $6.25/BOE for the third quarter of 2001. Third quarter operating expenses tend to be higher as a result of increased maintenance costs, plant turnarounds and property tax charges which are incurred during this period. Operating expenses for the nine months ended September 30, 2002 increased 18% to $95.9 million from the comparable period in 2001 due to the Merger, however, after reflecting the higher production levels, operating expenses per BOE have been reduced to $5.71/BOE from $5.77/BOE during this time period. Enerplus expects operating costs to continue in this range to the end of 2002.

General and Administrative Expenses

General and administrative ("G&A") expenses were $3.4 million or $0.60/BOE for the three months ended September 30, 2002 compared to $1.6 million or $0.29/BOE for the same period in 2001. Net G&A costs for the third quarter of 2001 were lower than expected due to one-time adjustments for cost recoveries. G&A expenses for the nine months ended September 30, 2002 of $10.1 million are in line with annual expectations of $0.60/BOE.

In accordance with the full cost method of accounting, Enerplus capitalized $2.0 million or 25% of gross G&A costs for the three months ended September 30, 2002 compared to $1.8 million or 28% for the same period in 2001. For the nine month period ended September 30, 2002, Enerplus capitalized $6.1 million of gross G&A costs compared to $4.6 million for the comparable period in 2001. The majority of these capitalized costs represent compensation costs for staff involved in development and acquisition activities.

Management Fees

($ millions)	Three Months ended September 30, 2002	Three Months ended September 30, 2001	Nine Months ended September 30, 2002	Nine Months ended September 30, 2001
Base management fees	$ 2.3	$ 2.5	$ 6.3	$ 7.0
Performance fees	4.9		7.3	
Total management fees	$ 7.2	$ 2.5	$ 13.6	$ 7.0

Base management fees, which are calculated based on 2.75% of net operating income, decreased to $2.3 million during the three months ended September 30, 2002 from $2.5 million for the same period in 2001. The decrease is a result of lower net operating income experienced during the period. For the nine months ended September 30, 2002, base management fees decreased to $6.3 million from $7.0 million for the same period in 2001. The decrease in the nine month comparison is a result of lower net operating income experienced during the period, offset slightly by the increase in the rate used to calculate the base management fees from 2.20% to 2.75%, as a result of the restructured management fee associated with the Merger.

The performance fee can range between 0% and 4% of the Fund's annual operating income based on the total return of the Fund and the relative performance compared to other senior oil and gas trusts. Although the performance fee is determined on December 31, 2002, management has accrued a performance fee based on the fact that, had the calculation been performed at September 30, 2002, the performance fee for 2002 would be 3.0% of net operating income. The $7.3 million is an estimate that may increase or decrease throughout the remainder of the year until the performance fee is calculated and finalized at December 31.

Interest Expense

Interest expense for the three months ended September 30, 2002 was $5.2 million, an increase from $5.1 million recognized during the comparable period of 2001. Although the Fund's average long-term debt has decreased compared to the same period in 2001, the average floating interest rate paid by the Fund has increased.

For the nine months ended September 30, 2002, interest expense was $12.7 million, a decrease from $13.5 million recognized during the comparable period of 2001. The decrease is attributable to lower outstanding average long-term debt along with a reduction in interest rates over the period.

As at September 30, 2002, Enerplus had floating interest rates with respect to $94.2 million in bank debt and $268.3 million in senior unsecured debentures. However, with respect to this long-term debt, it had interest rate swaps on $75.0 million that fixed the rate of interest before stamping fees between 3.89% and 4.70% for three-year terms.

Depletion, Depreciation and Amortization

Depletion, depreciation and amortization decreased to $52.7 million or $9.42/BOE for the three months ended September 30, 2002 from $55.4 million or $9.98/BOE for the same period in 2001. Included in the 2001 balance are amortization costs related to deferred hedging assets amounting to $3.9 million that were fully amortized by the end of 2001. For the nine months ended September 30, 2002, depletion, depreciation and amortization was $158.9 million or $9.47/BOE compared to $135.9 million or $9.66/BOE for the same period in 2001. These differences are a result of the Merger. Higher production volumes during 2002 have increased the amount of depletion, depreciation and amortization expense, while the change in the overall depletable reserves has decreased the rate of

depletion, depreciation and amortization per BOE. When applying a ceiling test to our capital assets as at September 30, 2002, no write down was required.

Taxes

For the three months ended September 30, 2002, a future income tax recovery of $11.1 million was recorded in income. Under Canadian generally accepted accounting principles, the Fund does not recognize any future income taxes as taxable income is distributed to Unitholders in the form of taxable distributions. However, the Fund's operating companies are required to account for future income taxes. Future income taxes for the operating companies are dependent upon the method by which funds are transferred to the Fund from the operating companies. The future income tax recovery occurs when tax deductible distributions, which can take the form of interest or royalties, are transferred from the operating companies to the Fund's Unitholders. During the quarter, increased tax deductible distributions were made from the operating companies to the Fund.

Netbacks

Netbacks per BOE of production (6:1)	**Three Months ended September 30,**		**Nine Months ended September 30,**	
For the period ended September 30,	**2002**	**2001**	**2002**	**2001**
Oil and gas sales	**$ 27.08**	$ 29.51	**$ 25.52**	$ 35.01
Royalties	**(5.19)**	(5.94)	**(5.27)**	(8.22)
Operating costs	**(6.21)**	(6.25)	**(5.71)**	(5.77)
Operating netback per BOE	**$ 15.68**	$ 17.32	**$ 14.54**	$ 21.02
General and administrative costs	**(0.60)**	(0.29)	**(0.60)**	(0.45)
Management fees	**(1.30)**	(0.45)	**(0.80)**	(0.49)
Net interest	**(0.92)**	(0.90)	**(0.74)**	(0.91)
Capital taxes	**(0.22)**	(0.25)	**(0.24)**	(0.26)
Total cash netback per BOE	**$ 12.64**	$ 15.43	**$ 12.16**	$ 18.91

Net Income and Funds Flow From Operations

	Three Months ended September 30,		**Nine Months ended September 30,**	
($ millions) except per trust unit amounts	**2002**	**2001**	**2002**	**2001**
Net income	$ 29.1	$ 25.1	$ 64.5	$ 143.3
Net income per trust unit	$ 0.41	$ 0.39	$ 0.92	$ 2.82
Funds flow from operations	$ 69.6	$ 85.0	$ 200.9	$ 264.6
Funds flow from operations per trust unit	$ 0.98	$ 1.31	$ 2.87	$ 5.22

The increase in net income for the three months ended September 30, 2002, is a result of higher average crude oil prices recognized during the third quarter of 2002 compared to the same period in 2001, offset slightly by the additional performance fee that has been accrued during the period. The decrease in funds flow from operations for the three months ended September 30, 2002 is due to an $18.9 million gain recognized from natural gas hedging contracts during the same period in 2001.

The change in net income and funds flow from operations for the nine months ended September 30, 2002, is due to a combination of a $16.2 million gain recognized from natural gas hedging contracts during 2001, a sharp decline in natural gas prices realized during 2002 from those experienced during

the first and second quarters of 2001 and the fact that the 2001 year-to-date results are those strictly of EnerMark to the date of the Merger.

Management monitors the Fund's distribution payout policy with respect to forecast cash flows, debt levels, and spending plans. Management is prepared to adjust the payout levels in an effort to balance the investor's desire for distributions with the Fund's requirement to maintain a prudent capital structure.

The following table reconciles Enerplus' "Funds Flow from Operations" as per the Statement of Cash Flows with the cash available for distribution to Unitholders.

Reconciliation of Cash Available for Distribution for the Period ($ millions except per unit amounts)	**Three Months ended September 30, 2002**	**Three Months ended September 30, 2001**	**Nine Months ended September 30, 2002**	**Nine Months ended September 30, 2001**
Funds flow from operations	**$ 69.6**	$ 84.9	**$ 200.9**	$ 264.6
Cash withheld for debt reduction	**(3.9)**	(5.6)	**(33.9)**	(32.2)
Enerplus cash flows				16.9
Accruals *	**(1.2)**	2.3	**3.5**	4.6
Cash available for distribution	**$ 64.5**	$ 81.6	**$ 170.5**	$ 253.9
Cash available for distribution per trust unit	**$ 0.88**	$ 1.25	**$ 2.40**	$ 4.77

* According to the Royalty Agreement with Enerplus Resources Corporation, the royalty paid to the Fund must be on a cash basis. As a consequence, the change in accrued net revenues for the period is added back to (deducted from) funds flow from operations for purposes of this reconciliation.

With respect to the third quarter of 2002, Enerplus distributed $64.5 million, or $0.88 per trust unit in cash distributions to Unitholders (94% of funds flow from operations) and withheld $3.9 million or $0.05 per trust unit for debt reduction (6% of funds flow from operations). For the nine month period, Enerplus has distributed $170.5 million, or $2.40 per trust unit (83% of funds flow from operations) and withheld $33.9 million or $0.48 per trust unit for debt reduction (17% of funds flow from operations).

Cash available for distribution per trust unit of $0.88 for the three months ended September 30, 2002 represents what an Enerplus Unitholder will have received from the production relating to the third quarter of 2002 (paid to Unitholders on September 20, October 20, and November 20, 2002). Cash available for distribution was $1.25 per trust unit for the same period in 2001.

Capital Expenditures

During the three months ended September 30, 2002, Enerplus spent $46.1 million (2001 $41.9 million) on capital expenditures prior to acquisitions and divestitures with a focus on development drilling in the Joarcam area. During the nine months ended September 30, 2002, Enerplus spent $101.0 million (2001 $95.0 million) on capital expenditures prior to acquisitions and divestitures. The capital program to enhance light oil production at Joarcam invested $19.5 million to drill, complete and tie-in 11 Viking Oil wells and construct the associated production facilities. The Medicine Hat North 50 well shallow natural gas development program is near completion and additional compression capacity has been completed at a cost of $8.6 million. Enerplus participated in the drilling of three natural gas wells at Mount Benjamin, a non-operated property, at a cost of $4.7 million. Two of the wells were successfully completed with the third near completion at the end of the quarter.

Capital expenditures are in line with those anticipated for the three and nine months ended September 30, 2002. The Fund expects annual capital expenditures of approximately $145.0 million in 2002 which has increased from the original estimate of $130.0 million as a result of opportunities identified in acquired and existing properties.

Capital Expenditures ($ millions)	**Three Months ended September 30, 2002**	**Three Months ended September 30, 2001**	**Nine Months ended September 30, 2002**	**Nine Months ended September 30, 2001**
Development drilling and recompletions	**$ 32.0**	$ 25.9	**$ 60.4**	$ 53.7
Plant and facilities	**12.8**	15.2	**34.7**	36.2

	Three Months ended September 30,		Nine Months ended September 30,	
Land and seismic	**0.3**	0.3	**2.0**	4.0
Office	**1.0**	0.5	**3.9**	1.1
Total capital spending	**46.1**	41.9	**101.0**	95.0
Acquisitions of oil and gas properties	**25.4**	57.2	**48.3**	60.0
Dispositions of non-core oil and gas properties	**(0.3)**	(34.8)	**(2.4)**	(54.8)
Net capital expenditures	**$ 71.2**	$ 64.3	**$ 146.9**	$ 100.2

Acquisitions of oil and natural gas properties for the nine months ended September 30, 2002 are comprised primarily of the acquisition of a 16% working interest in Oil Sands Lease #24 for $16.4 million, along with the acquisition of an additional interest in the Medicine Hat Glauconite C property during the first quarter 2002 for $20.5 million.

Through the remainder of the year, Enerplus will continue to pursue acquisition opportunities while maintaining a focused effort on the development of existing reserves that provide attractive potential economic returns to Unitholders.

Liquidity and Capital Resources

Enerplus' long-term debt as at September 30, 2002 of $362.5 million, which was comprised of bank credit facilities of $94.2 million and senior unsecured notes of $268.3 million was lower than long-term debt of $412.6 million as at December 31, 2001. The decrease in debt can be attributed to the equity issue on September 12, 2002 combined with cash from operations that has been withheld for debt repayments.

Financial Leverage and Coverage Ratios	**Nine Months ended September 30, 2002**	**Year ended December 31, 2001**
Long-term debt to funds flow from operations	**1.3 x**	1.2 x
Funds flow from operations to interest expense*	**16.4 x**	19.3 x
Long-term debt to long-term debt plus equity	**21%**	23%

* Funds flow from operations to interest expense ratio is based on the first nine months of 2002 plus the last three months of 2001.

During the second quarter of 2002, Enerplus diversified its debt portfolio through the issuance of US$175 million senior, unsecured notes with a coupon rate of 6.62% priced at par (the "Notes"). The Notes have a final maturity of June 19, 2014, with amortizing payments of 20% per annum on each of the five anniversary dates commencing on June 19, 2010. Concurrent with the issuance of the Notes, Enerplus swapped the US$175 million into Canadian dollar denominated floating rate debt at an exchange rate of 1.5333 for gross proceeds of $268.3 million at a floating interest rate, based on Canadian three month banker's acceptances, plus 1.18%. This cross currency swap on the senior

unsecured notes represented a mark-to-market gain of $40.0 million as at September 30, 2002. The Notes provide the Fund with a new source of financing and the assurance of long-term credit commitments at attractive rates.

On September 12, 2002, Enerplus closed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127,538,000 (net $120,886,000). These proceeds were used to reduce the amounts outstanding on the bank credit facilities.

As at September 30, 2002, Enerplus had a borrowing base limit of $620 million with respect to its bank credit facilities and senior unsecured debentures. This limit is based on the bank's evaluation of the value of Enerplus' proven oil and gas reserves. As of November 7, 2002, this limit was increased to $700 million. As a result, Enerplus' bank credit facilities were increased by $80 million from $351.7 million to $431.7 million.

On October 21, 2002, Enerplus closed the acquisition of Celsius Energy Resources Ltd. for total consideration of $165.9 million. This acquisition was financed from Enerplus' revolving credit facility.

Trust Unit Information

Enerplus had 74,751,000 trust units and no warrants outstanding at September 30, 2002 compared to 65,044,000 trust units and 2,238,000 warrants at September 30, 2001. The weighted average number of trust units outstanding during the third quarter of 2002 was 70,850,000 (2001 64,776,000). The weighted average number of trust units outstanding for the nine months ended September 30, 2002 was 70,066,000 (2001 50,738,000).

Taxability of Distributions

In the current commodity price environment, Enerplus expects that approximately 65% of the distributions paid to Canadian Unitholders in 2002 will be taxable and the remaining 35% will be treated as a tax deferred return of capital.

Forward-Looking Statements

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of Enerplus. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed above, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Accordingly, readers are cautioned that events or circumstances could cause results to differ materially from those predicted.

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ENERPLUS RESOURCES FUND
CONSOLIDATED BALANCE SHEET

($ thousands) (Unaudited)	September 30, 2002	December 31, 2001
ASSETS		
Current assets		
Cash and cash equivalents	**$ 3,471**	$ 979
Accounts receivable	**75,638**	100,089
Other current	**3,377**	4,869
	82,486	105,937
Property, plant and equipment	**2,814,368**	2,667,504
Accumulated depletion and depreciation	**(643,572)**	(489,188)
	2,170,796	2,178,316
Deferred charges (Note 4)	**1,847**	
	$ 2,255,129	$ 2,284,253
LIABILITIES		
Current liabilities		
Accounts payable	**$ 76,582**	$ 72,341
Distributions payable to unitholders	**22,426**	20,860
Payable to related party (Note 3)	**10,392**	7,915
	109,400	101,116

($ thousands) (Unaudited)	September 30, 2002	December 31, 2001
Long-term debt (Note 4)	**362,458**	412,589
Future income taxes	**314,222**	333,560
Accumulated site restoration	**58,538**	55,403
Deferred credits	**4,848**	6,591
Payable to related party (Note 3)	**1,525**	1,909
	741,591	810,052
EQUITY		
Unitholders' capital (Note 2)	**1,958,521**	1,826,507
Accumulated income	**389,069**	324,570
Accumulated cash distributions	**(943,452)**	(777,992)
	1,404,138	1,373,085
	$ 2,255,129	$ 2,284,253
Number of Trust Units outstanding (thousands)	**74,751**	69,532

ENERPLUS RESOURCES FUND
CONSOLIDATED STATEMENT OF INCOME

($ thousands except per unit amounts) (Unaudited)	Three Months Ended September 30		Nine Months Ended September 30	
	2002	2001	2002	2001
REVENUES				
Oil and gas sales	**$ 151,286**	$ 163,824	**$ 428,408**	$ 492,420
Crown royalties	**(21,161)**	(24,231)	**(66,013)**	(89,536)
Freehold and other royalties	**(7,823)**	(8,713)	**(22,502)**	(26,032)
	122,302	130,880	**339,893**	376,852
Interest and other income	**31**	110	**338**	680
	122,333	130,990	**340,231**	377,532
EXPENSES				
Operating	**34,689**	34,717	**95,853**	81,157
General and administrative	**3,352**	1,633	**10,085**	6,367
Management fees (Note 3)	**7,216**	2,497	**13,571**	6,957
Interest (Note 5)	**5,169**	5,121	**12,705**	13,473
Depletion, depreciation and Amortization	**52,656**	55,423	**158,906**	135,885
	103,082	99,391	**291,120**	243,839
Income before taxes	**19,251**	31,599	**49,111**	133,693

	Three Months Ended September 30		Nine Months Ended September 30	
Capital taxes	**1,294**	1,352	**3,950**	3,624
Future income tax	**(11,124)**	5,106	**(19,338)**	(13,260)
NET INCOME	**$ 29,081**	$ 25,141	**$ 64,499**	$ 143,329
Net income per trust unit				
Basic	$ 0.41	$ 0.39	$ 0.92	$ 2.82
Diluted	$ 0.41	$ 0.39	$ 0.92	$ 2.82
Weighted average number of Units outstanding (thousands)				
Basic	70,850	64,776	70,066	50,738
Diluted	71,019	64,853	70,181	50,817

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CONSOLIDATED STATEMENT OF ACCUMULATED INCOME

($ thousands) (Unaudited)	**Three Months Ended September 30**		**Nine months Ended September 30**	
	2002	**2001**	**2002**	**2001**
Accumulated income, beginning of period	**$ 359,988**	$ 262,489	**$ 324,570**	$ 144,301
Net income	**29,081**	25,141	**64,499**	143,329
Accumulated income, end of Period	**$ 389,069**	$ 287,630	**$ 389,069**	$ 287,630

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ENERPLUS RESOURCES FUND
CONSOLIDATED STATEMENT OF CASH FLOWS

($ thousands) (Unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2002	**2001**	**2002**	**2001**
OPERATING ACTIVITIES				
Net income	**$ 29,081**	$ 25,141	**$ 64,499**	$ 143,329
Depletion, depreciation and Amortization	**52,656**	55,423	**158,906**	135,885
Future income tax	**(11,124)**	5,106	**(19,338)**	(13,260)
Site restoration and abandonment Costs incurred	**(1,023)**	(719)	**(3,130)**	(1,343)
Funds flow from operations	**69,590**	84,951	**200,937**	264,611
Decrease (increase) in non-cash Operating working capital	**1,787**	(7,565)	**21,832**	(35,779)
	71,377	77,386	**222,769**	228,832
FINANCING ACTIVITIES				

	Three Months Ended September 30		Nine Months Ended September 30	
Issue of trust units, net of Issue costs	**124,591**	11,253	**131,274**	45,845
Cash distributions to unitholders	**(61,323)**	(92,677)	**(163,894)**	(252,512)
Increase (decrease) in long-term Debt	**(78,351)**	79,768	**(50,131)**	93,325
Payment to related party (Note 3)	**(128)**	(127)	**(384)**	(127)
Deferred charges			**(1,892)**	
	(15,211)	(1,783)	**(85,027)**	(113,469)
INVESTING ACTIVITIES				
Property, plant and equipment	**(54,366)**	(101,495)	**(137,696)**	(156,323)
Proceeds on sale of property, Plant and equipment	**308**	34,755	**2,446**	61,581
Corporate acquisitions		(8,792)		(20,594)
	(54,058)	(75,532)	**(135,250)**	(115,336)
Increase in cash	**2,108**	71	**2,492**	27
Cash, beginning of period	**1,363**	802	**979**	846
Cash, end of period	**$ 3,471**	$ 873	**$ 3,471**	$ 873
Funds flow from operations per unit	**$ 0.98**	$ 1.31	**$ 2.87**	$ 5.22
SUPPLEMENTARY CASH FLOW INFORMATION				
Cash income taxes paid	**$**	$	**$**	$
Cash interest paid	**$ 2,099**	$ 5,373	**$ 9,483**	$ 13,278

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CONSOLIDATED STATEMENT OF ACCUMULATED CASH DISTRIBUTIONS

($ thousands) (Unaudited)	Three Months Ended September 30 2002	2001	Nine Months Ended September 30 2002	2001
Accumulated cash distributions, Beginning of period	**$ 881,863**	$ 619,051	**$ 777,992**	$ 447,158
Cash distributions to unitholders	**61,589**	87,712	**165,460**	259,605
Accumulated cash distributions, end of period	**$ 943,452**	$ 706,763	**$ 943,452**	$ 706,763

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SELECTED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

(Tabular amounts in thousands of Canadian dollars and thousands of units except per unit amounts)

1. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of Enerplus Resources Fund ("Enerplus" or the "Fund") have been prepared by management following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2001 except as stated below. The note disclosure requirements for annual statements provide additional disclosure to that required for these interim statements. Accordingly, these interim statements should be read in conjunction with the

Fund's consolidated financial statements for the year ended December 31, 2001. The disclosures provided below are incremental to those included in the 2001 annual consolidated financial statements.

(a)

The accounting of the merger of EnerMark Income Fund ("EnerMark") and Enerplus Resources Fund ("Enerplus") which occurred on June 21, 2001 ("the Merger"), applied the reverse takeover form of the purchase method of accounting for business combinations. Accordingly, these consolidated financial statements of the Fund include the accounts of the merged Fund for the nine months ended September 30, 2002 but the comparative figures for the prior year include the accounts of EnerMark as at and for the nine months ended September 30, 2001, plus the results of Enerplus from June 21, 2001 to September 30, 2001.

All numbers of trust units and Warrants up to the June 21, 2001 Merger date have been restated using the merger exchange ratio of 0.173 EnerMark unit for each Enerplus unit (the "Merger Exchange Ratio").

(b)

Effective for the fiscal years beginning on or after January 1, 2002, the Fund adopted the recommendations of the CICA on accounting for stock-based compensation which apply to new rights granted on or after that date. The Fund has elected to continue to measure compensation cost based on the intrinsic value of the award at the date of the grant and recognize that cost over the vesting period. As the exercise price of the rights granted approximates the market price of the trust units at the grant date, no compensation cost has been provided in the consolidated statement of income.

The exercise price of the rights granted under the Fund's rights plan may be reduced in future periods in accordance with the terms of the rights plan. The amount of the reduction cannot be reasonably determined as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of the amounts to be withheld from future distributions to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

2. FUND CAPITAL

(a)

Unitholders' Capital

Authorized: Unlimited Number of Trust Units

	September 30, 2002		December 31, 2001	
Issued: (thousands)	**Units**	**Amount**	**Units**	**Amount**
Balance, beginning of period	**69,532**	**$ 1,826,507**	40,925	$ 1,050,986
Issued for cash:				
Pursuant to public offerings	**4,750**	**120,886**	4,313	101,039
Pursuant to Option Plans	**98**	**1,905**	135	2,530
Pursuant to exercise of warrants			1,197	33,319
Pursuant to expiry of warrants				2,846
Issued pursuant to the deemed Acquisition of Enerplus (Note 1)			20,863	582,364
Issued pursuant to the management agreement (Note 3)			173	5,000
Distribution Reinvestment & Unit Purchase Plan	**340**	**8,483**	659	16,577
Issued for acquisition of Property interests	**31**	**740**	1,267	31,846
Balance, end of period	**74,751**	**$ 1,958,521**	69,532	$ 1,826,507

On September 12, 2002, Enerplus closed an equity offering of 4,750,000 trust units at a price of $26.85 per trust unit for gross proceeds of $127,538,000 (net $120,886,000).

(b)

Trust Unit Option Plan

As at September 30, 2002, 150,000 options issued pursuant to the Trust Unit Option Plan were outstanding, representing 0.2% of the total units outstanding. Activity for the options issued pursuant to the option plan is summarized as follows:

	September 30, 2002		December 31, 2001	
(thousands except per Unit amounts)	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Options outstanding at beginning of period	**264**	**$ 20.93**	363[1]	$ 21.03
Exercised	**(98)**	**$ 19.55**	(55)	$ 21.94
Cancelled	**(16)**	**$ 22.73**	(44)	$ 20.47
Options outstanding at end of period	**150**	**$ 21.75**	264	$ 20.93
Options exercisable at end of period	**119**		99	

(1) Number of options representing the balance at June 21, 2001 after the Merger of EnerMark and Enerplus.

No new options have been granted under the Trust Unit Option Plan as this plan was superseded by the Trust Unit Rights Incentive Plan discussed below.

(c)

Trust Unit Rights Incentive Plan

As at September 30, 2002, a total of 1,348,000 rights were issued (2,740,000 reserved) pursuant to the Trust Unit Rights Incentive Plan of which none are exercisable. Under the Incentive Plan, distributions per trust unit to Enerplus Unitholders in a calendar quarter which

represent a return of more than 2.5% of the net property, plant and equipment of Enerplus at the end of such calendar quarter would result in a reduction in the exercise price of the rights. Based on second and third quarter 2002 results, the exercise price has been calculated to be reduced by $0.07 per trust unit (effective October 2002) and $0.14 per trust unit (effective January 2003) respectively.

As it is not possible to determine the fair value of rights granted under the plan, compensation costs for pro forma disclosure purposes has been determined based on the excess of the unit price over the exercise price at the date of the financial statements. For the three and nine months ended September 30, 2002, net income would be reduced by $150,000 and $183,000, for the estimated compensation cost associated with rights granted under the plan on or after January 1, 2002 with a negligible impact on net income per trust unit during these periods.

Activity for the rights issued pursuant to the Incentive Plan is as follows:

	September 30, 2002		December 31, 2001	
(thousands except per Unit amounts)	Number of Rights	Weighted Average Exercise Price	Number of Rights	Weighted Average Exercise Price

	September 30, 2002			December 31, 2001		
Rights outstanding at Beginning of period	**1,318**	**$**	**24.50**			
Granted	**145**	**$**	**26.66**	1,360	$	24.50
Cancelled	**(115)**	**$**	**24.47**	(42)	$	24.50
Rights outstanding at End of period	**1,348**	**$**	**24.63**	1,318	$	24.50

3. RELATED PARTY TRANSACTIONS

Management, advisory and administration services are supplied to the Fund on a fee and cost reimbursement basis, pursuant to an agreement with Enerplus Global Energy Management Company ("EGEM"). Management fees of $13,571,000 are reported on the consolidated statement of income for the nine months ended September 30, 2002. This included earned base management fees of $6,291,000 and accrued performance fees of $7,280,000. The performance fees are not determined until December 31, 2002, and as such, this amount may increase or decrease throughout the remainder or the year. As at September 30, 2002, $9,883,000 was payable to EGEM, pursuant to this agreement.

In addition, pursuant to a share purchase agreement related to the Merger, the Fund acquired shares of Enerplus Resources Corporation from EGEM for $2,545,000 payable over five years in quarterly installments of $127,000 through a reduction of management fees. At September 30, 2002, the indebtedness remaining pursuant to this agreement was $2,035,000 of which $509,000 has been classified as current.

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In addition to the transactions described above, Enerplus has entered into financial instrument contracts at prevailing market rates with an indirect subsidiary of El Paso Corporation, the ultimate parent of EGEM, as described in Note 5.

4. LONG-TERM DEBT

		September 30, 2002		December 31, 2001
Bank credit facilities	**$**	**94,130**	$	412,589
Senior unsecured notes		**268,328**		
Total long-term debt	**$**	**362,458**	$	412,589

The senior unsecured notes (the "Notes") were issued on June 19, 2002 in the amount of US$175,000,000. They have a final maturity of June 19, 2014 and bear interest at 6.62% per annum, with interest paid semi-annually on June 19 and December 19 of each year. The Note Purchase Agreement requires the Fund to make five annual amortizing principal repayments of 20% of the initial principal amount, commencing on June 19, 2010.

Concurrent with the issuance of the Notes, the Fund entered into a cross currency swap, with a syndicate of major financial institutions. Under the terms of the swap, the amount of the Notes was fixed for purposes of interest and principal repayments at a notional amount of CDN$268,328,000. Interest payments are made on a floating rate basis, set at the rate for three-month Canadian banker's acceptances, plus 1.18%. Costs incurred in connection with issuing the Notes, in the amount of $1,892,000, are being amortized over the term of the Notes. As at September 30, 2002, the amount not amortized associated with these costs was $1,847,000.

Subsequent to September 30, 2002 the Fund's borrowing base was increased to $700,000,000. The increase resulted in the amount of credit available under the bank credit facilities (the "Facilities") being increased to $431,672,000 from $351,672,000. The Facilities remain unsecured and consist of a $402,000,000 revolving committed line with an incremental two-year term, and a $29,672,000 demand operating line. Various borrowing options are available under the Facilities including prime rate based advances and banker's acceptance loans.

5. FINANCIAL INSTRUMENTS

The Fund uses various types of financial instruments to manage the risk related to fluctuating commodity prices. The fair values of these instruments are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the instruments outstanding as at September 30, 2002 with reference to forward prices and mark-to-market valuations provided by independent sources. The Fund may be exposed to losses in the event of default by the counterparties to these instruments. This credit risk is controlled by the Fund through the selection of financially sound counterparties.

Interest rate and cross currency swaps:

In addition to the cross currency swap described in Note 4, the Fund has entered into various interest rate swaps on a notional amount of bank debt, as follows:

Term	Notional Amount	Fixed Rate(1)
January 18, 2002 to January 18, 2005	$ 25 million	3.89%
June 3, 2002 to June 3, 2005	25 million	4.70%
June 4, 2002 to June 4, 2005	25 million	4.65%
	$ 75 million	

(1) Before banking fees that are expected to range between 0.85% and 1.05%.

The mark-to-market values of the $75.0 million interest rate swaps as at September 30, 2002, represent an unrealized loss of $2.0 million. The mark-to-market value of the cross currency interest rate swap related to the Senior Unsecured Notes as at September 30, 2002 represented an unrealized gain of $40.0 million.

Crude oil:

Enerplus has entered into the following financial option contracts on its gross crude oil production that are designed to reduce a downward impact of crude oil prices. The remaining costs to be amortized associated with these contracts are approximately $215,000. The mark-to-market value of the financial crude oil contracts as at September 30, 2002 reflects an unrealized loss of $8,979,000.

		WTI Crude Oil Price US $		
Term	Volume Bbls/day	Sold Call	Purchased Put	Sold Put
July 1, 2002 Dec. 31, 2002				
3-way	1,500	US$ 27.00	US$ 19.50	US$ 16.00
3-way(1)	1,500	US$ 25.00	US$ 19.50	US$ 17.00
3-way	2,175	US$ 27.00	US$ 19.50	US$ 17.00
3-way	1,500	US$ 28.00	US$ 20.10	US$ 17.00
3-way(2)	1,500	US$ 31.00	US$ 22.00	US$ 19.50
3 way(2)	1,500	US$ 30.00	US$ 24.00	US$ 21.35
Oct. 1, 2002 Sept. 30, 2004				
3-way(2)	1,500	US$ 29.00	US$ 22.00	US$ 19.25
Jan. 1, 2003 Sept. 30, 2004				
3-way(2)	1,500	US$ 30.00	US$ 23.00	US$ 20.00
Jan. 1, 2003 Dec. 31, 2003				
3-way	1,500	US$ 27.00	US$ 19.50	US$ 17.00

			WTI Crude Oil Price US $		
3-way		1,500	US$ 28.00	US$ 20.15	US$ 17.00
3-way(2)		1,500	US$ 28.51	US$ 22.00	US$ 19.50
Jan. 1, 2003	June 30, 2004				
3-way(2)		1,500	US$ 28.00	US$ 22.50	US$ 19.60
3-way(2)		500	US$ 28.00	US$ 22.50	US$ 19.90
Jan. 1, 2003	December 31, 2004				
3-way(3)		1,500	US$ 29.50	US$ 22.00	US$ 20.00

(1) The counterparty to this 3-way crude oil option is a subsidiary of El Paso Corporation which is the ultimate parent of EGEM (refer to Note 3) and the amount receivable/payable with respect to this transaction is currently not material. The remaining option premium for this instrument is $69,000 and is being amortized over the remaining term.

(2) Financial option transactions entered into during the third quarter of 2002.

(3) Transactions entered into subsequent to September 30, 2002 that are not included in the mark-to-market values.

Natural Gas:

In addition to the crude oil price protection initiatives described previously, Enerplus also has physical and financial contracts in place on its gross natural gas production as described below. The remaining costs to be amortized associated with these contracts are $0.01 per trust unit or $509,000 in 2002 and $0.02 per trust unit or $1,694,000 in 2003. The mark-to-market value of the financial natural gas contracts as at September 30, 2002 reflects an unrealized loss of $17,981,000.

	MMcf/day	AECO $/Mcf CDN$				
Term	**Daily Volumes**	**Sold Call**	**Purchased Put**	**Sold Put**	**Fixed Price**	**Escalated Price**
July 1, 2002 Oct. 31, 2002						
Physical	3.8				$ 2.63	
Physical	8.5				$ 3.97	
Collar(1)	9.5	$ 5.27	$ 3.69			
Put(1)	9.5		$ 3.69			
3-way	9.5	$ 4.22	$ 3.29	$ 2.37		
July 1, 2002 Dec. 31, 2002						
Physical	2.8				$ 2.64	
Physical	2.0					$ 2.01
Swap	3.8		$ 2.90			
Collar	7.6	$ 4.22	$ 3.43			
Collar	5.7	$ 4.81	$ 3.43			
Collar	14.2	$ 4.22	$ 3.32			
Nov. 1, 2002 Dec. 31, 2002						
Collar(1)	7.1	$ 5.27	$ 3.69			
Put(1)	7.1		$ 3.69			
Call	9.5	$ 6.33				
Nov. 1, 2002 Mar. 31, 2003						
3-way(2)(3)	4.8	$ 7.39	$ 5.28	$ 4.22		
3-way(4)(5)	4.8	$ 7.39	$ 5.28	$ 4.22		
Jan. 1, 2003 Mar. 31, 2003						

	MMcf/day	AECO $/Mcf CDN$				
Call	9.5	$ 6.33				
Jan. 1, 2003 Oct. 31, 2003						
Physical	2.8				$ 2.64	
Collar(1)	7.1	$ 5.27	$ 3.69			
Put(1)	7.1		$ 3.69			

	MMcf/day					
Jan. 1, 2003 Dec. 31, 2003						
Physical	2.0					$ 2.23
Swap	3.8		$ 2.90			
3-way	9.5	$ 7.91	$ 4.27	$ 3.17		
Jan. 1, 2003 June 30, 2004						
3-way	9.5	$ 7.39	$ 4.75	$ 3.17		
Jan. 1, 2003 Sept. 30, 2004						
3-way(2)	9.5	$ 6.67	$ 4.75	$ 3.17		
3-way(2)	9.5	$ 7.39	$ 4.75	$ 3.69		
Jan. 1, 2003 Oct. 31, 2006						
Swap(5)	9.5		$ 5.47			
Apr.1, 2003 Oct. 31, 2003						
Collar(2)	4.8	$ 6.25	$ 4.75			
Collar(5)	4.8	$ 6.25	$ 4.75			
Jan. 1, 2004 Oct. 31, 2004						
Swap	3.8		$ 2.90			
2004 2010						
Physical	2.0					$ 2.33

(1) The counterparty to these natural gas collars and puts is a subsidiary of El Paso Corporation which is the ultimate parent of EGEM (refer to Note 3) and the amounts receivable/payable with respect to these transactions are currently not material. The remaining option premiums for these instruments are $2,203,000 and are being amortized over their remaining terms.

(2) Additional transactions entered into during the third quarter of 2002.

(3) Enerplus sells physical gas at the Month Index less $0.05/Mcf.

(4) Enerplus sells physical gas at the Month Index less $0.11/Mcf.

(5) Transactions entered into subsequent to September 30, 2002 that are not included in the mark-to-market values.

6. COMMITMENTS AND CONTINGENCIES

The acquisition of the working interest in Oil Sands Lease #24 (Joslyn Creek Lease) included the assumption of approximately $4,100,000 in contingent project debt that was comprised of $3,360,000 of principal and approximately $740,000 in accrued interest. Interest is accrued at the Bank of Canada prime business rate and is not compounded. The debt is contingent on both production and pricing hurdles with respect to development on the lease. As it is too early in the development of this project to determine if these hurdles will be satisfied, the contingent debt has not been accrued in the consolidated financial statements.

7. SUBSEQUENT EVENT

Subsequent to September 30, 2002, the Fund acquired all of the issued and outstanding shares of Celsius Energy Resources Ltd., a private oil and gas company, for total cash consideration of approximately $165.9 million including working capital adjustments. The acquisition will be

accounted for by the purchase method with the results of operations included in the consolidated financial statements of the Fund from the closing date of October 21, 2002.

DIRECTORS

Douglas R. Martin(3)(4)(5)(8)
President, Charles Avenue Capital Corp.
Calgary, Alberta

André Bineau(1)
Vice President, Association de bienfaisance et de retraite des policiers et policières de la Ville de Montréal
Montréal, Québec

Derek J.M. Fortune(3)(4)(9)
Secretary/Manager, Superannuation Fund,
City of Ottawa
Ottawa, Ontario

Gordon J. Kerr(4)
President & Chief Executive Officer,
Enerplus Global Energy Management Company
Calgary, Alberta

Robert L. Normand(1)(3)(6)
Corporate Director,
Montréal, Québec

Eric P. Tremblay(2)
Senior Vice President, Capital Markets,
Enerplus Global Energy Management Company
Calgary, Alberta

Harry B. Wheeler(1)(2)(7)
President,
Colchester Investments Ltd.
Calgary, Alberta

Robert L. Zorich
Managing Director,
EnCap Investments L.C.
Houston, Texas

(1) Audit & Risk Management Committee

(2) Environment, Safety & Reserves Committee

(3) Corporate Governance Committee

(4) Compensation & Human Resources Committee

(5) Chairman of the Board

(6) Chairman of the Audit & Risk Management Committee

(7) Chairman of the Environment, Safety & Reserves Committee

(8) Chairman of the Corporate Governance Committee

(9) Chairman of the Compensation & Human Resources Committee

OFFICERS

Gordon J. Kerr
President & Chief Executive Officer

Robert J. Waters
Senior Vice President & Chief Financial Officer

Heather J. Culbert
Senior Vice President, Corporate Services

Garry A. Tanner(10)
Senior Vice President, Business Development

Eric P. Tremblay
Senior Vice President, Capital Markets

Jo-Anne M. Caza
Vice President, Investor Relations

Daryl W. Cook
Vice President, Operations

Wayne T. Foch
Vice President, Finance

Gerald F. Stevenson
Vice President, Acquisitions

Rodney D. Gray
Controller, Finance

Christina S. Meeuwsen
Corporate Secretary

Wayne G. Ford
Controller, Operations

(10) Officer of Enerplus Global Energy Management Company only

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CORPORATE INFORMATION

OPERATING COMPANIES OWNED BY ENERPLUS RESOURCES FUND

EnerMark Inc.
Enerplus Resources Corporation

LEGAL COUNSEL
Blake, Cassels & Graydon LLP
Calgary, Alberta and Toronto, Ontario

AUDITORS
Deloitte & Touche LLP
Calgary, Alberta

TRANSFER AGENT
The CIBC Mellon Trust Company
Calgary, Alberta
Toll free: 1-800-387-0825
Email: inquiries@cibcmellon.com

CO-TRANSFER AGENT
Mellon Investor Services L.L.C.
Ridgefield, New Jersey

INDEPENDENT RESERVE ENGINEERS
Sproule Associates Limited
Calgary, Alberta

STOCK EXCHANGE LISTINGS AND TRADING SYMBOLS
New York Stock Exchange: ERF
Toronto Stock Exchange: ERF.un

HEAD OFFICE

The Dome Tower
3000, 333 - 7th Avenue S.W.
Calgary, Alberta T2P 2Z1

Telephone: (403) 298-2200
Toll free: 1-800-319-6462
Fax: (403) 298-2211
Email: investorrelations@enerplus.com

For more information, visit our website:
www.enerplus.com

ABBREVIATIONS
AECO Alberta Energy Company interconnect with the Nova Gas System
ARTC Alberta Royalty Tax Credit
bbl(s)/day barrel(s) per day
BOE(s)/day barrel of oil equivalent per day (6 Mcf gas = 1 bbl crude oil)
Mbbls thousand barrels
MBOE thousand barrels of oil equivalent

Mcf/day thousand cubic feet per day
MMbbl(s) million barrels
MMBOE million barrels of oil equivalent
MMcf/day million cubic feet per day
NYSE New York Stock Exchange
TSX Toronto Stock Exchange
W.I. percentage working interest of ownership
WTI West Texas Intermediate oil at Cushing, Oklahoma

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENERPLUS RESOURCES FUND

By: /s/ Christina S. Meeuwsen

Christina S. Meeuwsen
Corporate Secretary
DATE: November 14, 2002

QuickLinks

EXHIBIT 1