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

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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

EXHIBIT 1

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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

For the nine months ended September 30,	CDN$ 2002	CDN$ 2001(1)	US$(2) 2002	US$(2) 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 30^{th}, 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.

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 co