Bonterra
Energy Income Trust

2004 INTERIM REPORT

For the six months ended June 30, 2004

Highlights	Three Months Ended June 30 2004	Three Months Ended June 30 2003[2]	Six Months Ended June 30 2004	Six Months Ended June 30 2003[2]
FINANCIAL				
Revenue – oil and gas				
(net of royalties)	**$11,223,000**	$ 9,310,000	**$22,010,000**	$19,265,000
Funds Flow from Operations [1]	**$ 6,936,000**	$ 4,907,000	**$13,429,000**	$11,095,000
Per Unit - Basic	**$ 0.51**	$ 0.37	**$ 0.99**	$ 0.83
Per Unit - Diluted	**$ 0.50**	$ 0.37	**$ 0.97**	$ 0.83
Net Earnings	**$ 4,336,000**	$ 3,075,000	**$ 8,584,000**	$ 7,291,000
Per Unit - Basic	**$ 0.32**	$ 0.23	**$ 0.63**	$ 0.55
Per Unit - Diluted	**$ 0.31**	$ 0.23	**$ 0.62**	$ 0.55
Cash Distributions	**$ 0.43**	$ 0.40	**$ 0.82**	$ 0.81
Capital Expenditures	**$ 832,000**	$ 1,055,000	**$ 3,429,000**	$ 1,573,000
Total Assets			**$79,804,000**	$77,780,000
Debt			**$ 2,781,000**	$20,960,000
Unitholders Equity			**$57,987,000**	$40,276,000
OPERATIONS				
Oil and NGL's - Barrels Per Day	**2,349**	2,382	**2,375**	2,391
Natural Gas - MCF Per Day	**4,643**	4,297	**4,642**	4,478

(1) Funds flow from operations is not a recognized measure under GAAP. Management believes that in addition to net earnings, funds flow from operations is a useful supplemental measure as it demonstrates the Trust's ability to generate the cash necessary to make trust distributions, repay debt or fund future growth through capital investment. Investors are cautioned, however, that this measure should not be construed as an indication of the Trust's performance. The Trust's method of calculating this measure may differ from other issuers and accordingly, it may not be comparable to that used by other issuers. For these purposes, the Trust defines funds flow from operations as funds provided by operations before changes in non-cash operating working capital items.

(2) Figures have been restated to conform to current accounting policies. See notes to financial statements.

Report to Unitholders

Bonterra Energy Income Trust (the Trust) is pleased to report its results for the first six months of 2004. The Trust has been successful in generating substantial increases in net revenue, funds flow and net earnings on a gross and per unit basis. Cash distributions based on operations for the first six months of 2004 were $0.82 per unit ($11,336,000 or 84 percent of funds flow) compared to $0.81 per unit ($10,828,000 or 98 percent of funds flow) for the first six months of 2003.

At the end of the second quarter the Trust was successful in completing a financing that resulted in the issuance of 1,100,000 units at a price of $19.50 per unit for total proceeds of $21,450,000. The funds will be used mainly for the exploration and development of shallow gas and coal bed methane (CBM) properties and general corporate purposes. This is the first time the Trust has issued units for cash, other than for employee unit options, since it was formed on July 1, 2001. The Trust is not changing its main objective to continue replacing its annual decline from annual funds flow. However, the board of directors and management determined that the capital expenditures that may be required for the numerous shallow gas and CBM wells that will be completed in 2004 and 2005 would result in creating a debt level in excess of one year's funds flow, which the Trust is uncomfortable with.

The Trust has an inventory of land that allow for the potential drilling of more than 400 gross CBM and shallow gas wells, most of which the Trust will have a high working interest. Depending on success, the Trust anticipates drilling or recompleting 40 wells in 2004 and 60 in 2005.

At June 30, 2004 the Trust had bank debt of $2,781,000, which is approximately one month funds flow. The debt level will increase in the future as the Trust continues with its 2004 and 2005 capital programs.

A Discussion of Financial and Operational Results

The following report dated August 1, 2004 is a review of the operations, current financial position and outlook for the Trust and should be read in conjunction with the unaudited financial statements for the six months ended June 30, 2004, including the notes related thereto, and the audited financial statements for the fiscal year ended December 31, 2003, together with the notes related thereto.

Average daily production volume for the six months ended June 30, 2004 was 3,149 barrels of oil equivalent (BOE's) per day. BOE's are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation.

Production consists of 2,375 barrels per day of crude oil and natural gas liquids and 4,642 MCF per day of natural gas. Bonterra's first half 2003 average production was 3,137 BOE's per day consisting of 2,391 barrels per day of crude oil and natural gas liquids and 4,478 MCF per day of natural gas.

Production increases over previous year's numbers were tempered by the planned annual maintenance turnarounds at all three of the Trust's main Pembina gas processing facilities during the second quarter. These turnarounds lasted a total of five weeks and resulted in a shutting in of approximately 200 BOE's per day of production. The overall effect was an average production impact of 60 BOE's per day through the quarter.

The Trust filed an application in the third quarter of 2003 with the Alberta Energy and Utilities Board (AEUB) requesting reduced drill spacing for CBM in the Pembina area of Alberta. This request has been approved and will assist in increasing the recovery of CBM as well as increase the number of 100 percent owned wells the Trust can drill. The Trust has plans for drilling and or re-completion of approximately 25 CBM wells in 2004. Approval was also received from the AEUB to co-mingle some of the zones from the Edmonton gas sand formation. This will allow for duel completions in wells that have production from more than one Edmonton sand zone.

During the first six months the Trust drilled eleven (net 9.75) shallow gas wells and two (net two) CBM wells. All of which were successful. Five of the wells were put on production in late March, two late April, two in May and one in June with the remaining three wells anticipated to be on production by the end of August.

Net revenue from petroleum and natural gas sales was $22,010,000 in the first half of 2004 compared to $19,265,000 for the six months ended June 30, 2003. The increase in net revenue over the corresponding 2003 period was due primarily to higher net commodity prices. The average Canadian price received net of hedging adjustments for crude oil and natural gas liquids during the first six months of 2004 was $43.19 per barrel and $6.86 per MCF for natural gas compared to $40.92 per barrel and $5.56 per MCF in the corresponding 2003 period. Substantial increases in the price of U.S. WTI oil prices and U.S. Nymex natural gas pricing were partially offset by the rising Canadian dollar. The negative impact on the first half of 2004 compared to the first half of 2003 to the Trust's funds flow from operations of the rising Canadian dollar was approximately 20 cents per unit and approximately 18 cents per unit on net earnings. The Trust incurred a $1,089,000 (2003 - $2,662,000) hedging loss during the first half of 2004. The Trust currently has fixed price contracts for approximately 20 percent of its estimated future 12 month oil production and has costless collars for about 40 percent of its next 12 months natural gas production which guarantees a floor price and a maximum high price. Please see note seven to the financial statements for a current listing of the Trust's outstanding hedging agreements.

Production costs for the six months ended June 30, 2004 were $7,617,000 compared to $7,091,000 for the six months ended June 30, 2003. On a BOE basis production costs averaged $13.29 in 2004 verses $12.49 in the corresponding 2003 period. Inflationary increases in maintenance costs were the primary reason for the production cost increase.

The Trust's production comes primarily from low productivity wells. These wells generally result in higher production costs on a per unit-of-production basis as costs such as municipal taxes, surface lease, power and personnel costs are not variable with production volumes. As the Trust develops its shallow natural gas potential, the average costs per BOE should decline. The high production costs for the Trust are substantially offset by low royalty rates of approximately 10 percent, which is much lower than industry average for conventional production and results in high cash net backs on a combined basis despite higher than average production costs.

General and administrative expenses were $752,000 in the first six months of 2004 compared to $747,000 in the six months ended June 30, 2003. Costs on a BOE bases were virtually unchanged at $1.31 per BOE in the first half of 2004 compared to $1.32 per BOE in the first half of 2003. The decline of $100,000 in the second quarter 2004 general and administrative expenses from the first quarter 2004 amount was primarily due to costs associated with the third party engineering report which are incurred in the first quarter of each year.

Interest expense decreased to $407,000 for the six months ended June 30, 2004 compared to $445,000 for the six months ended June 30, 2003. The 2004 average amount of outstanding debt was approximately the same as the corresponding 2003 period as the Trust's public offering that raised a gross amount of $21,450,000 did not close until June 30, 2004. An approximate one percent decrease in interest rates was the primary factor in the decrease in interest expense.

Provision for depletion, depreciation and accretion was $4,005,000 and $3,709,000 for the six month periods ending June 30, 2004 and June 30, 2003 respectively. The increase was primarily due to depletion resulting from the additional drilling done by the Trust during 2003 and 2004. The 2004 change in accounting policy related to the accounting for the Trust's asset retirement obligation (formerly future site restoration) did not result in a significant change in the Trust's provision for depletion, depreciation and accretion.

Funds flow from operations increased by $2,334,000 from $11,095,000 in the first six months of 2003 to $13,429,000 in the first six months of 2004. The increase in 2004 was due to higher net commodity prices after adjusting for hedging losses partially offset by higher production costs. The following reconciliation compares funds flow to the Trusts net earnings as calculated according to Canadian generally accepted accounting principles:

For the periods ended June 30	**Three Months**		**Six Months**	
	2004	**2003**	**2004**	**2003**
Net earnings for the period	**$4,336,000**	$3,075,000	**$ 8,584,000**	$7,291,000
Unit option expense	**70,000**	70,000	**124,000**	110,000
Depletion, depreciation and accretion	**2,002,000**	1,890,000	**4,005,000**	3,709,000
Future income taxes	**528,000**	(128,000)	**716,000**	(15,000)
Funds flow from operations	**$6,936,000**	$4,907,000	**$13,429,000**	$11,095,000

Net earnings for the first half of 2004 were $8,584,000 compared to $7,291,000 in the corresponding 2003 period. The increase was primarily due to increased commodity prices offset partially by higher production costs and increased future tax provision.

Two new expenses were required to be reported in 2004 due to regulatory changes. Due to the change in accounting policy regarding the reporting of stock-based compensation plans, the Trust reported a $124,000 expense (2003 restated amount of $110,000). The Trust also reported an accretion expense of $279,000 (2003 restated amount of $273,000), that has been included in depletion, depreciation and accretion expense, relating to the discounting of its asset retirement obligation. The accretion expense represents the discount rate used to calculate the Trust's asset retirement obligation. The rate the Trust uses in the calculation is a credit-adjusted risk-free interest rate of 5 percent. This rate is reviewed annually and if changed may have a substantial impact on the present value of the asset retirement obligation.

During the first quarter of 2004, the Trust provided a temporary operating loan to Novitas Energy Ltd. (Novitas), a company with common directors and management. The loan has an interest rate of bank prime plus one-half percent. There is no security provided for the loan, however, the management agreement in place between Novitas and the Trust, originally established as a 90 day automatic renewal, can not be terminated as long as the loan remains outstanding. Interest paid on the loan during the first six months of 2004 was $28,000.

During the six months ended June 30, 2004 the Trust received a management fee from Novitas for management services of $20,000 (2003 - $10,000) per month plus five percent of before tax net earnings. Total receipts during the first six months of 2004 were $142,000 (2003 - $93,000). Novitas also paid administrative fees on a per well basis to the Trust for the administration of its oil and gas properties. Total amounts paid during the first six months of 2004 were $96,000 (2003 - $73,000).

Comaplex Minerals Corp. (Comaplex) a company with common directors and management paid a management fee to the Trust for management services of $20,000

(January to June - $10,000 and July to December $25,000, in 2003) per month. Total amounts paid during the first six months of 2004 were $120,000 (2003 - $60,000). At December 31, 2003 the Trust owed Comaplex $3,750,000 which was repaid prior to June 30, 2004.

The above charges all represent the fair value of the services rendered.

During the first six months of 2004, the Trust incurred capital costs of $3,520,000 consisting primarily of $2,253,000 for drilling and completing of 13 (net 11.75) natural gas wells, $375,000 for drilling of non-operated infill oil wells, and $513,000 for tying in and increasing the deliverability of natural gas wells drilled in 2003.

The Trust currently has plans to drill or recomplete a further 30 net shallow gas (including CBM) wells in 2004. In addition, five net oil wells are anticipated to be drilled by the Trust prior to the end of 2004. Drilling success in 2004 should substantially increase our production and reserves. Further infill drilling to enhance crude oil production is planned in several areas where the Trust has non-operated interests. The Trust will participate with the operator of the properties on these prospects.

Additional information relating to the Trust may be found on SEDAR.COM.

Outlook

The Trust continues to operate on a conservative basis. It has low debt, high netbacks and one of the highest reserve life indexes in the oil and gas trust sector. For the next few years the Trust will continue to drill its inventory of shallow gas, CBM and infill oil prospects, and will also continue to evaluate potential acquisitions. The board and management are optimistic with regard to its annual distributions from the prospective of increased production. Obviously distributions are also influenced by commodity prices and the strength of the Canadian dollar.

For further information please visit our website at www.bonterraenergy.com.

Submitted on behalf of the Board of Directors,

George F. Fink
President, CEO and Director

Management's Responsibility for Financial Statements

The information provided in this report, including the financial statements, is the responsibility of management. In the preparation of these statements, estimates are sometimes necessary to make a determination of future values for certain assets or liabilities. Management believes such estimates have been based on careful judgements and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Trust's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Our auditors have not performed a review of these interim financial statements. The audit committee has reviewed these financial statements with management and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this interim report.

Consolidated Statements of Operations and Accumulated Earnings

For the periods ended June 30 (unaudited)

	Three Months 2004	Three Months 2003 (Restated see Note 1)	Six Months 2004	Six Months 2003 Restated see Note 1)
Revenue				
Oil and gas sales,				
net of royalties	**$11,223,000**	$9,310,000	**$22,010,000**	$19,265,000
Production costs	**(3,894,000)**	(3,896,000)	**(7,617,000)**	(7,091,000)
Alberta royalty tax credits	**51,000**	51,000	**117,000**	121,000
Interest and other	**61,000**	4,000	**79,000**	8,000
	7,441,000	5,469,000	**14,589,000**	12,303,000
Expenses				
General and administrative	**326,000**	280,000	**752,000**	747,000
Interest on long-term debt	**179,000**	269,000	**407,000**	445,000
Unit option expense (Note 1)	**70,000**	70,000	**124,000**	110,000
Depletion, depreciation and				
accretion (Note 1)	**2,002,000**	1,890,000	**4,005,000**	3,709,000
	2,577,000	2,509,000	**5,288,000**	5,011,000
Earnings before Income Taxes	**4,864,000**	2,960,000	**9,301,000**	7,292,000
Income Taxes (Recovery)				
Current	**–**	13,000	**1,000**	16,000
Future	**528,000**	(128,000)	**716,000**	(15,000)
	528,000	(115,000)	**717,000**	1,000
Net Earnings for the Period	**4,336,000**	3,075,000	**8,584,000**	7,291,000
Accumulated earnings at				
beginning of period	**35,567,000**	21,593,000	**31,319,000**	17,377,000
Accumulated Earnings at				
End of Period	**$39,903,000**	$24,668,000	**$39,903,000**	$24,668,000
Net Earnings per Trust Unit				
– Basic	**$0.32**	$0.23	**$0.63**	$0.55
Net Earnings per Trust Unit				
– Diluted	**$0.31**	$0.23	**$0.62**	$0.55

Consolidated Statements of Cash Flows

For the periods ended June 30 (unaudited)

	Three Months 2004	Three Months 2003 (Restated see Note 1)	Six Months 2004	Six Months 2003 Restated see Note 1)
Operating Activities				
Net earnings for the period	**$4,336,000**	$3,075,000	**$8,584,000**	$7,291,000
Items not affecting cash				
Unit option expense (Note 1)	**70,000**	70,000	**124,000**	110,000
Depletion, depreciation and accretion	**2,002,000**	1,890,000	**4,005,000**	3,709,000
Future income taxes	**528,000**	(128,000)	**716,000**	(15,000)
	6,936,000	4,907,000	**13,429,000**	11,095,000
Change in non-cash operating working capital items				
Accounts receivable	**(207,000)**	657,000	**(1,403,000)**	576,000
Crude oil inventory	**(91,000)**	19,000	**38,000**	(65,000)
Parts Inventory	**25,000**	18,000	**(26,000)**	(12,000)
Prepaid Expenses	**(422,000)**	(254,000)	**(481,000)**	(301,000)
Accounts payable and accrued liabilities	**(1,028,000)**	(1,044,000)	**737,000**	(875,000)
	(1,723,000)	(604,000)	**(1,135,000)**	(677,000)
Cash Provided by Operating Activities	**5,213,000**	4,303,000	**12,294,000**	10,418,000
Financing Activities				
Increase (decrease) in debt	**(19,705,000)**	2,233,000	**(19,049,000)**	1,716,000
Decrease (increase) in due from related party (Note 2)	**400,000**	-	**(400,000)**	-
Proceeds on issuance of units pursuant to public offering	**21,450,000**	-	**21,450,000**	-
Unit issue costs	**(1,178,000)**	-	**(1,178,000)**	-
Unit option proceeds	**285,000**	-	**1,151,000**	-
Unit distributions	**(5,591,000)**	(5,481,000)	**(10,748,000)**	(10,561,000)
Cash Used in Financing Activities	**(4,339,000)**	(3,248,000)	**(8,774,000)**	(8,845,000)
Investing Activities				
Property and equipment expenditures	**(874,000)**	(1,055,000)	**(3,520,000)**	(1,573,000)
Cash Used in Investing Activities	**(874,000)**	(1,055,000)	**(3,520,000)**	(1,573,000)
Net Cash Inflow	**-**	-	**-**	-
Cash, beginning of period	**-**	-	**-**	-
Cash, End of Period	**$-**	$-	**$-**	$-
Cash Interest Paid	**$179,000**	$269,000	**$407,000**	$445,000
Cash Taxes Paid	**$-**	$13,000	**$1,000**	$16,000

Consolidated Balance Sheets

As at June 30, 2004 (unaudited)
and December 31, 2003

	2004	2003 (Restated see Note 1)
Assets		
Current		
Accounts receivable	**$5,908,000**	$4,505,000
Crude oil inventory (Note 1)	**624,000**	662,000
Parts inventory	**386,000**	360,000
Due from related party (Note 2)	**400,000**	-
Prepaid expenses	**1,197,000**	716,000
Investments in related party (Note 3)	**461,000**	461,000
Total Current Assets	**8,976,000**	6,704,000
Property and Equipment (Note 4)		
Petroleum and natural gas properties and related equipment	**96,064,000**	92,636,000
Accumulated depletion and depreciation	**(25,236,000)**	(21,504,000)
Net Property and Equipment	**70,828,000**	71,132,000
	$79,804,000	$77,836,000
Liabilities		
Current		
Distributions payable	**$-**	$1,623,000
Accounts payable and accrued liabilities	**6,540,000**	5,803,000
Debt (Note 5)	**2,781,000**	21,830,000
Total Current Liabilities	**9,321,000**	29,256,000
Future Income Tax Liability	**1,101,000**	385,000
Asset Retirement Obligations (Note 1)	**11,395,000**	11,214,000
Total Liabilities	**21,817,000**	40,855,000
Unitholders' Equity		
Unit capital (Note 6)	**73,236,000**	51,764,000
Contributed surplus	**306,000**	231,000
Accumulated earnings	**39,903,000**	31,319,000
Accumulated cash distributions	**(55,458,000)**	(46,333,000)
Total Unitholders' Equity	**57,987,000**	36,981,000
	$79,804,000	$77,836,000

Consolidated Statements of Unitholders' Equity

For the periods ended June 30 (unaudited)

	Three Months 2004	Three Months 2003 (Restated see Note 1)	Six Months 2004	Six Months 2003 Restated see Note 1)
Unitholders' equity, beginning of period	**$38,615,000**	$42,722,000	**$36,981,000**	$42,075,000
Net earnings for the period	**4,336,000**	3,075,000	**8,584,000**	7,291,000
Net capital contributions (Note 6)	**20,557,000**	-	**21,423,000**	-
Stock option adjustment	**70,000**	-	**124,000**	-
Cash distributions	**(5,591,000)**	(5,481,000)	**(9,125,000)**	(9,090,000)
Unitholders' Equity, End of Period	**$57,987,000**	$40,316,000	**$57,987,000**	$40,276,000

Notes to the Consolidated Interim Financial Statements

Periods ended June 30, 2004 and 2003 (unaudited)

1. Significant Acccounting Policies

The accounting policies and methods of application followed in the preparation of the interim financial statements are the same as those followed in the preparation of the Trust's 2003 annual financial statements except for the following items. The interim financial statements as presented should be read in conjunction with the 2003 annual financial statements.

- Stock-based compensation plan

  Effective January 1, 2004 the Trust adopted the Canadian Institute of Chartered Accountants ("CICA") section 3870, "Stock-based Compensation and Other Stock-based Payments", retroactively with restatement of prior periods. The recommendations require the Trust to record a compensation expense over the vesting period based on the fair value of options granted to employees and directors.

  The change resulted in the following amendments to figures for the three months and six months ended June 30, 2003 and balances as at December 31, 2003:

	Three Months 2003 As reported	Three Months 2003 Restated	Six Months 2003 As reported	Six Months 2003 Restated
Unit option expense	$ -	$ 70,000	$ -	$ 110,000
Unit capital			51,137,000	51,172,000
Contributed surplus (December 31, 2003)			-	231,000
Accumulated earnings (January 1, 2003)			17,841,000	17,786,000
Accumulated earnings (December 31, 2003)			31,879,000	31,613,000

- Asset retirement obligations

Effective January 1, 2004 the Trust retroactively adopted the CICA section 3110, "Asset Retirement Obligations". The new recommendations require that the recognition of the fair value of obligations associated with the retirement of tangible long-life assets be recorded in the period the asset is put into use, with a corresponding increase to the carrying amount of the related asset. The obligations recognized are statutory, contractual or legal obligations. The liability is adjusted over time for changes in the value of the liability through accretion charges which are included in depletion, depreciation and accretion expense. The costs capitalized to the related assets are amortized to earnings in a manner consistent with the depletion and depreciation of the underlying asset.

The change resulted in the following amendments to figures for the three months and six months ended June 30, 2003 and balances as at December 31, 2003:

	Three Months		Six Months	
	2003 As reported	2003 Restated	2003 As reported	2003 Restated
Depletion, depreciation and accretion	$1,928,000	$1,890,000	$ 3,799,000	$ 3,709,000
Future income tax expense (recovery)	(155,000)	(128,000)	(42,000)	(15,000)
Unit capital			51,172,000	51,764,000
Accumulated earnings (January 1, 2003)			17,786,000	17,882,000
Accumulated earnings (December 31, 2003)			31,613,000	31,820,000
Petroleum and natural gas properties and related equipment			87,032,000	92,636,000
Accumulated depletion and depreciation			(19,545,000)	(21,366,000)
Asset retirement obligations			8,573,000	11,214,000
Future income tax liability			41,000	385,000

At June 30, 2004, the estimated total undiscounted amount required to settle the asset retirement obligations was $28,360,000. These obligations will be settled based on the useful lives of the underlying assets, which extend up to 40 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of 5 percent.

Changes to asset retirement obligations were as follows:

	Six months ended June 30, 2004
Asset retirement obligations, December 31, 2003	$ 11,214,000
Adjustment to opening asset retirement obligation	(7,000)
Liabilities settled during period	(91,000)
Accretion	279,000
Asset retirement obligations, June 30, 2004	$ 11,395,000

- Crude oil inventory

Effective January 1, 2004 the Trust will record its crude oil inventory at the lower of cost and net realizable value. Inventory cost is determined based on combined average per barrel operating costs, royalties and depletion and depreciation for the period and net realizable value is determined based on sales price in the month preceding period end. The change resulted in the following amendments to figures for the three months and six months ended June 30, 2003 and balances as at December 31, 2003:

	Three Months		Six Months	
	2003 As reported	2003 Restated	2003 As reported	2003 Restated
Oil and gas sales, net of royalties	$9,108,000	$9,310,000	$19,354,000	$19,265,000
Production costs	3,880,000	3,896,000	7,150,000	7,091,000
Accumulated earnings (January 1, 2003)			17,882,000	17,377,000
Accumulated earnings (December 31, 2003)			31,820,000	31,319,000
Accounts receivable			5,530,000	4,505,000
Crude oil inventory			-	662,000
Accumulated depletion and depreciation			(21,366,000)	(21,504,000)

- Hedging relationships

The CICA published an amended Accounting Guideline 13, “Hedging Relationships”, effective January 1, 2004, to clarify circumstances in which hedge accounting is appropriate. All derivative instruments that do not qualify as a hedge under the guideline, or are not properly designated as a hedge, will be recorded on the balance sheet as either an asset or liability with changes in fair value recognized in earnings.

The Trust adopted the standard January 1, 2004 with no impact on the financial results.

Derivative financial instruments are utilized to reduce commodity price risk on the Trust's product sales. The Trust does not enter into financial instruments for trading or speculative purposes.

The Trust's policy is to formally designate each derivative financial instrument as a hedge of a specifically identified product sale. The Trust believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term to maturity, the production volume in the instruments all match the production being hedged.

The commodity price swap agreements are used as part of the Trust's program to manage its product pricing. The commodity price swap agreements involve the periodic exchange of payments and are recorded as adjustments of net revenue. During the six month period ended June 30, 2004 the Trust recorded a reduction to net revenue of $1,089,000 (Six months ended June 30, 2003 - $2,662,000)

The cumulative impact of the above described accounting changes to the first six months of 2003 was a reduction in net earnings of $77,000 and no change on a per unit in Basic and Diluted Earnings per Trust Unit.

2. Related Party Transactions

During the first quarter of 2004, the Trust provided a temporary operating loan to Novitas Energy Ltd. (Novitas), a company with common directors and management. The loan has an interest rate of bank prime plus one-half percent. There is no security provided for the loan, however, the management agreement in place between Novitas and the Trust, originally established as a 90 day automatic renewal, can not be terminated as long as the loan remains outstanding. Interest paid on the loan during the first six months of 2004 was $28,000.

During the six months ended June 30, 2004 the Trust received a management fee from Novitas for management services of $20,000 (2003 - $10,000) per month plus five percent of before tax net earnings. Total receipts during the first six months of 2004 were $142,000 (2003 - $93,000). Novitas also paid administrative fees on a per well basis to the Trust for the administration of its oil and gas properties. Total amounts paid during the first six months of 2004 were $96,000 (2003 - $73,000).

Comaplex Minerals Corp. a company with common directors and management paid a management fee to the Trust for management services of $20,000 (January to June -

$10,000 and July to December $25,000, in 2003) per month. Total amounts paid during the first six months of 2004 were $120,000 (2003 - $60,000).

The above charges all represent the fair value of the services rendered.

3. Investments

Investments consist entirely of 689,682 (December 31, 2003 – 689,682) common shares in Comaplex (See note 2). The investment is recorded at cost with the fair market value based on the trading price of stock at June 30, 2004 of $1,897,000 (December 31, 2003 - $2,931,000). The common shares trade on the Toronto Stock Exchange under the symbol CMF. The investment represents less than a two percent ownership in the outstanding shares of Comaplex. At December 31, 2003 the Trust owed Comaplex $3,750,000 which was repaid prior to June 30, 2004.

4. Property and Equipment

	June 30, 2004		December 31, 2003	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Undeveloped land	$ 187,000	$ -	$ 186,000	$ -
Petroleum and natural gas properties and related equipment	95,187,000	25,002,000	91,774,000	21,311,000
Furniture, equipment and other	690,000	234,000	676,000	193,000
	$96,064,000	$25,236,000	$92,636,000	$21,504,000

5. Debt

The Trust has a bank revolving credit facility of $32,000,000 at June 30, 2004 (December 31, 2003 - $32,000,000). The terms of the credit facility provide that the loan is due on demand and is subject to annual review. The credit facility has no fixed payment requirements. The amount available for borrowing under the credit facility is reduced by the amount of outstanding letters of credit. As of June 30, 2004, the Trust has $1,851,000 (December 31, 2003 - $234,000) of outstanding letters of credit. Collateral for the loan consists of a demand debenture providing a first floating charge over all of the Trust's assets, and a general security agreement.

Fourteen million dollars of the credit facility carries an interest rate of Canadian chartered bank prime with the balance at one-quarter percent above prime. As of June 30, 2004, the Trust had an outstanding balance under the facility of $2,781,000 (December 31, 2003 - $17,466,000). The Trust has classified borrowing under its bank facilities as a current liability as required by guidance under the CICA's Emerging Issues Committee Abstract 122. It has been management's experience that these types of loans which are required to be classified as a current liability are seldom called by principal bankers as long as all the terms and conditions of the loan are complied with. Cash interest paid during the six month period ended June 30, 2004 for this loan was $370,000 (corresponding 2003 period - $286,000).

As at December 31, 2003, the Trust had a balance payable of $3,750,000 to Comaplex (see notes 2 and 3). The loan has been repaid prior to June 30, 2004. The interest rate was bank prime less three-quarters of a percent. The security provided by the Trust for the loan was that the Trust has agreed to maintain a line of credit with its principal banker sufficient to repay the loan if demanded. Cash interest paid during the six month period ended June 30, 2004 for this loan was $37,000 (corresponding 2003 period - $158,000).

6. Unit Capital

Authorized

The Trust is authorized to issue an unlimited number of trust units without nominal or par value

Issued	Number	Amount
Trust Units		
Balance, January 1, 2004	13,521,405	$51,764,000
Issued pursuant to Trust's unit option plan	115,500	1,151,000
Issued pursuant to public offering	1,100,000	21,450,000
Unit issue costs for public offering	-	(1,178,000)
Transfer of contributed surplus to unit capital	-	49,000
Balance, June 30, 2004	14,736,905	$73,236,000

The Trust sold 1,100,000 units at a price of $19.50 pursuant to a public offering which closed on June 30, 2004. Net proceeds after unit issue costs were $20,272,000.

See Note 1 regarding accounting for unit-based compensation plan.

7. Commitments – Future Sales Agreements

The Trust entered into the following commodity hedging transactions for a portion of its 2004 and 2005 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
July 1, 2004 to September 30, 2004	Crude Oil	500 barrels	WTI	$40.85 per barrel
October 1, 2004 to December 31, 2004	Crude Oil	500 barrels	WTI	$44.20 per barrel
January 1, 2005 to March 31, 2005	Crude Oil	500 barrels	WTI	$43.08 per barrel
April 1, 2005 to June 30, 2005	Crude Oil	500 barrels	WTI	$48.52 per barrel
July 1, 2005 to September 30, 2005	Crude Oil	500 barrels	WTI	$50.02 per barrel
April 1, 2004 to October 31, 2004	Natural Gas	1,500 GJ's	AECO	Floor of $4.75 and ceiling of $7.25 per GJ
April 1, 2004 to October 31, 2004	Natural Gas	2,000 GJ's	AECO	Floor of $5.75 and ceiling of $7.35 per GJ
November 1, 2004 to March 31, 2005	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $9.50 per GJ

8. Subsequent Event – Distribution

Subsequent to June 30, 2004, the Trust declared its distribution of $0.15 per unit payable on July 30, 2004 to Unitholders of record on July 15, 2004. The distribution represents earnings in the Trust for the month of June 2004.

Bonterra
Energy Income Trust

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