2004

Bonterra
Energy Income Trust

Annual Report

Bonterra
Energy Income Trust

Trust Profile

Bonterra Energy Income Trust. (TSX symbol – BNE.UN) is an energy income trust that develops and produces oil and natural gas in the Provinces of Alberta and Saskatchewan.

The Trust's business strategy is to strive to maximize Unitholder's value by applying long-term growth objectives. The Trust's primary objective is to combine its oil and gas production technical strengths with planned business strategies to generate above average results and returns for its Unitholders.

Contents

Notice of Annual General Meeting

The Annual General Meeting of Unitholders will be held on Monday, May 16, 2005, in the Nikiska Room, Main Lobby Level, at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 11:00 a.m.

Forward-Looking Information

Certain information set forth in this document, including management's assessment of Bonterra Energy Income Trust's ("the Trust" or "Bonterra") future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond Bonterra's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Bonterra's actual results, performance or achievement could differ materially from those expressed in, or implied by these forward-looking statements, and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits Bonterra will derive therefrom. Bonterra disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. Readers are cautioned that net present value of reserves does not represent fair market value of reserves.

Highlights

	2004	2003[5]
Financial ($000, except $ per share)		
Revenue – oil and gas (net of royalties)	$ **47,966**	$ 38,381
Distribution per Unit	**1.88**	1.55
Funds Flow from Operations (1)	**29,606**	22,228
Per Unit Basic	**2.08**	1.66
Per Unit Fully Diluted	**2.03**	1.64
Net Earnings	**20,366**	14,016
Per Unit Basic	**1.43**	1.05
Per Unit Fully Diluted	**1.40**	1.04
Capital Expenditures and Acquisitions	**10,943**	5,691
Outstanding Debt	**3,861**	21,830
Unitholders' Equity	**54,060**	36,983
Units Outstanding (000's)	**14,943**	13,521
Operations		
Oil and Liquids (barrels per day)	**2,361**	2,384
Average Price ($ per barrel)	$ **47.30**	$ 39.65
Natural Gas (MCF per day)	**4,996**	4,403
Average Price ($ per MCF)	$ **6.81**	$ 5.45
Total barrels per day (BOE per day) (2)	**3,194**	3,118
Reserves		
Oil and Liquids (barrels in 000's)		
Proven Developed Producing (Gross) (3)	**11,956**	11,032
Proven plus Probable (Gross) (3)	**16,084**	13,357
Natural Gas (MCF in 000's)		
Proven Developed Producing (Gross) (3)	**17,021**	15,978
Proven plus Probable (Gross) (3)	**21,762**	19,031
Reserve Life Index (Oil, liquids and natural gas @6:1)		
Proven Developed Producing (4)	**12.4**	11.8
Proven plus Probable (4)	**16.5**	14.3
Reserves in BOE's per Weighted Average Outstanding Unit		
Proven Developed Producing	**1.04**	1.01
Proven plus Probable	**1.39**	1.22
Trust Units Trading Statistics		
Unit Prices (based on daily closing price)		
High	**26.00**	15.85
Low	**15.15**	9.10
Close	**25.10**	15.50
Daily Average Trading Volume	**22,918**	14,576

(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) 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.

(3) Gross reserves relate to the Trusts ownership of reserves before royalty interests.

(4) The reserve life index is calculated by dividing the reserves (in BOE's) by the annualized fourth quarter average production rate in BOE/d (2004 - 3,268, 2003 – 3,172).

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

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Report to Unitholders

Bonterra Energy Income Trust ("Bonterra") is pleased to report its operational and financial results for the year and to provide information about its acquisition of Novitas Energy Ltd. (Novitas) on January 7, 2005. The Trust had a successful growth year and its annual distributions and capital appreciation resulted in a rate of return to Unitholders of 74 (2003 – 78) percent, far exceeding the return of most trusts and corporations.

Operations

Bonterra's production is ideally suited for a trust. Approximately 75 percent of its production is mainly light, sweet gravity crude and liquids, and the remaining 25 percent natural gas is sweet long-life production. The life index for the Trust's proven developed producing reserves is 12.4 years, which is significantly higher than most other trusts. Bonterra's life index including all categories of proven and probable reserves is 16.5 years. The reserves have been calculated by Sproule Associates Limited, independent engineers. Reserves in BOE's per weighted average outstanding units increased by 14 percent, from 1.22 in 2003 to 1.39 in 2004.

The long life index allows the Trust to distribute a higher percentage of its cash flow to Unitholders rather than using it for capital expenditures to maintain production volumes. Bonterra's annual actual decline rate from existing properties is approximately seven percent before capital expenditures.

Production volumes for 2004 averaged 3,194 barrels of oil equivalent (BOE's) per day compared to 3,118 BOE's per day in 2003. The December 31, 2004, exit production was approximately 3,330 BOE's per day. Six Pembina Cardium oil wells and five Pembina shallow gas wells were drilled in Q4, 2004, most of which should be on production by the end of Q2 2005. Bonterra has high working interests in these wells.

Acquisition of Novitas in January 2005

In January 2005 Bonterra was successful in acquiring 100 percent of all of the issued and outstanding shares of Novitas for $769,000 in cash and 1,335,745 units of Bonterra. Since the acquisition did not become effective until January 2005, this report does not include Novitas. At the closing in January 2005, Novitas production was approximately 600 BOE's.

Financial

Bonterra's distribution for 2004 was $1.88 compared to $1.55 for 2003. The taxable portion in 2004 was 58.51 (2003 – 68.92) percent and 41.49 (2003 – 31.08) percent is a return of capital.

Revenue (net of royalties) from commodity sales was $47,966,000 in 2004 compared to $38,381,000 for the preceding year. Commodity prices were $47.30 (2003 - $39.65) per barrel of oil and natural gas liquids, and $6.81 (2003 - $5.45) per MCF for natural gas.

At year-end Bonterra's debt was approximately $3,861,000 (2003 - $21,830,000), less than two months funds flow on an annualized basis. This level of debt falls within the Trusts objective of debt being less than one year's cash flow.

Outlook

The objectives for the Trust are to increase its production volumes and reserves in the future by developing its existing properties and by acquiring additional production. During 2005 Bonterra estimates that it will participate in drilling approximately 50 wells. The majority of these wells will be drilled on Trust operated and high working interest locations, mainly in the Cardium and shallow gas zones in the Pembina field. The Trust also continues to look for strategic acquisitions that compliment its portfolio and will provide a benefit to Unitholders over the long term.

The Trust is optimistic with regard to its drill programs and its ability to continue to provide high returns and additional appreciation of its unit price. It should be noted that since Bonterra Energy Corp. (predecessor to the Trust) was incorporated and listed publicly in mid 1998, for every $100 invested at that time, a Unitholder that held continuously from that date to December 31, 2004, would have received $1,279 in distributions and have Trust Units worth $5,553.

The Board of Directors of the operating company and management wish to thank the Unitholders for their continued loyal support and advice and the staff for the significant contributions made by them.

Submitted on behalf of the Board of Directors,

George F. Fink
President, CEO and Director

Reserves

The Trust engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of December 31, 2004. The reserves are located in the Provinces of Alberta and Saskatchewan. The majority of the Trust's production is comprised of light sweet crude, which results in higher oil prices, and better marketing opportunities. The Trust's main producing areas are located in the Pembina area of Alberta and Dodsland area of Saskatchewan. The gross reserve figure in the following charts represents the Trust's ownership interest before royalties and the net figure is after deductions for royalties.

Summary of Oil and Gas Reserves as of December 31, 2004

(Forecast Prices and Costs)

	Reserves					
	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserve Category	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved						
Developed Producing	10,758	10,301	17,021	12,797	1,198	860
Developed Non-Producing	150	137	422	365	12	8
Undeveloped	633	582	845	567	82	57
Total Proved	11,541	11,020	18,288	13,729	1,292	925
Probable	2,936	2,797	3,473	2,480	316	226
Total Proved Plus Probable	14,477	13,817	21,761	16,209	1,608	1,151

Reconciliation of Trust Gross Reserves by Principal Product Type

(Forecast Prices and Costs)

	Light and Medium Oil			Natural Gas		
	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf) (MMcf)	Gross Proved Plus Probable
December 31, 2003	10,618	1,864	12,482	16,634	2,397	19,031
Improved recovery	353	116	469	613	277	890
Technical revisions	1,374	956	2,330	2,869	799	3,668
Production	(804)	-	(804)	(1,828)	-	(1,828)
December 31, 2004	11,541	2,936	14,477	18,288	3,473	21,761

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Summary of Net Present Values of Future Net Revenue as of December 31, 2004

(Forecast Prices and Costs)

	Net Present Value of Future Net Revenue				
	Before and After Income Taxes Discounted at (%/year)				
(M$)	0	5	10	15	20
Reserve Category					
Proved					
Developed Producing	241,109	169,990	133,774	112,115	97,685
Developed Non-Producing	4,785	4,106	3,586	3,178	2,851
Undeveloped	11,759	8,305	6,104	4,572	3,433
Total Proved	257,653	182,401	143,464	119,865	103,969
Probable	79,957	35,042	19,901	13,397	9,647
Total Proved Plus Probable	337,610	217,443	163,365	133,072	113,616

Commodity prices used in the above calculations of reserves are as follows:

Year	Edmonton Par Price (Cdn $ per barrel)	Alberta Gas Reference Price Plantgate (Cdn $ per MCF)	Propane (Cdn $ per barrel)	Butane (Cdn $ per barrel)	Pentane (Cdn $ per barrel)
2005	51.25	6.76	32.09	38.20	52.49
2006	48.03	6.45	30.07	34.01	49.19
2007	42.64	6.00	26.70	30.20	43.67
2008	38.31	5.55	23.98	27.13	39.23
2009	36.36	5.21	22.76	25.75	37.24
2010	36.91	5.31	23.11	26.13	37.80
2011	37.47	5.38	23.46	26.53	38.37
2012	38.03	5.48	23.81	26.93	38.95
2013	38.61	5.58	24.17	27.34	39.54
2014	39.19	5.68	24.53	27.75	40.14
2015	39.78	5.79	24.90	28.17	40.74

Crude oil, natural gas and liquid prices escalate at 1.5% per year thereafter.

The following cautionary statements are specifically required by NI 51-101

- It should not be assumed that the estimates of future net revenue presented in the above tables represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variances could be material.
- Disclosure provided herein in respect of BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio of 6mcf:1bbl has been used in all cases in this disclosure. This BOE conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- Estimates of reserves and future net revenues for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties due to the effects of aggregation.

Production

The following table provides a summary of production volumes from the Trust's main producing areas:

	2004		2003	
	Oil and NGL (Bbls/day)	**Natural Gas (MCF/day)**	Oil and NGL (Bbls/day)	Natural Gas (MCF/day)
Pembina, Alberta	**1,729**	**4,231**	1,733	3,502
Dodsland, Saskatchewan	**388**	**207**	399	268
Pinto, Saskatchewan	**59**	**50**	50	53
Redwater, Alberta	**42**	**53**	46	72
Midale, Saskatchewan	**42**	**18**	42	15
Other	**101**	**437**	114	493
	2,361	**4,996**	2,384	4,403

Land Holdings

The Trust's holdings of petroleum and natural gas leases and rights are as follows:

	2004		2003	
	Gross Acres	**Net Acres**	Gross Acres	Net Acres
Alberta	**113,697**	**67,159**	113,057	66,519
Saskatchewan	**32,584**	**19,524**	32,584	19,524
	146,281	**86,683**	145,641	86,043

Petroleum and Natural Gas Capital Expenditures

The following table summarizes petroleum and natural gas capital expenditures incurred by the Trust on acquisitions, land, seismic, exploration and development drilling and production facilities for the years ended December 31:

	2004	2003
Acquisitions	**$ –**	$ 32,000
Exploration and development costs	**10,055,000**	5,226,000
Pipeline projects	**302,000**	30,000
Seismic	–	3,000
Land costs	**236,000**	96,000
Net petroleum and natural gas capital expenditures	**$10,593,000**	$5,387,000

Drilling History

The following table summarizes the Trust's gross and net drilling activity and success:

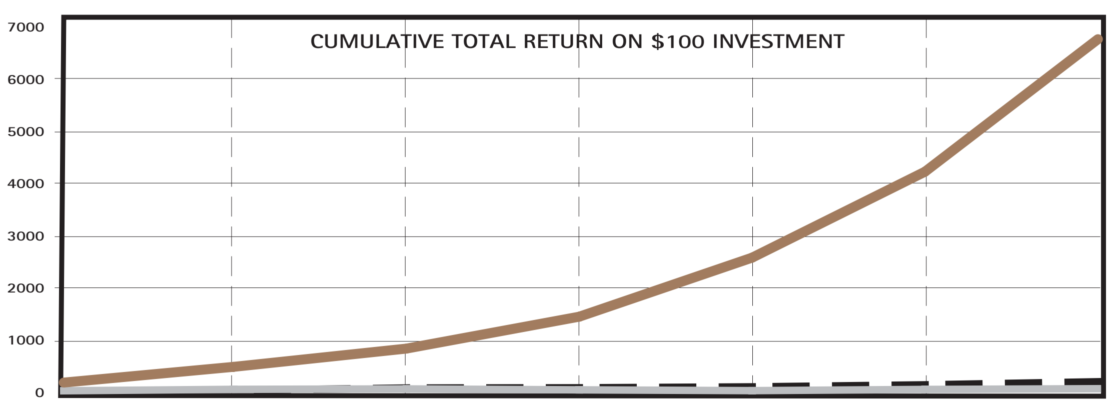
	2004					
	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude Oil	**19**	**5.8**	**–**	**–**	**19**	**5.8**
Natural Gas	**21**	**18.6**	**1**	**1**	**22**	**19.6**
Dry	**2**	**1.8**	**–**	**–**	**2**	**1.8**
Total	**42**	**26.2**	**1**	**1**	**43**	**27.2**
Success rate	**95.2%**	**93.1%**	**100%**	**100%**	**95.3%**	**93.3%**

	2003					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	31	3.27	–	–	31	3.3
Natural Gas	3	3.00	6	5.8	9	8.8
Dry	–	–	–	–	–	–
Total	34	6.27	6	5.8	40	12.1
Success rate	100%	100%	100%	100%	100%	100%

	2002					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	1	.1	–	–	1	0.1
Natural Gas	1	1.0	9	7.3	10	8.3
Dry	–	–	–	–	–	–
Total	2	1.1	9	7.3	11	8.4
Success rate	100%	100%	100.%	100%	100%	100%

Market Performance

The following graph illustrates changes over the past six and a half years in the value of $100 invested in Bonterra (of Common Shares of Bonterra Energy Corp. prior to July 1, 2001) or Trust Units, as the case may be, the TSX Composite Index and the TSX Energy Index



	Dec 1998	Dec 1999	Dec 2000	Dec 2001	Dec 2002	Dec 2003	Dec 2004
Bonterra Energy Income Trust [1]	$245	$550	$900	$1,512	$2,644	$4,292	$6,832
TSX Composite Index	$ 92	$119	$127	$ 109	$ 94	$ 117	$ 132
TSX Energy Index	$ 83	$ 99	$144	$ 148	$ 166	$ 205	$ 264

Note (1) Includes distributions of $5.66 per unit since becoming a Trust.

Property Discussions

Bonterra has an excellent asset base consisting of long life, low risk and predictable reserves with upside, and management that has proven it can manage these high quality assets to generate long-term value. Our producing properties are located in the Pembina area of Alberta, the East Central area of Alberta, the Dodsland area in southwest Saskatchewan, and the southeast area of Saskatchewan. Subsequent to year end Bonterra has added quality properties in the Shaunavon area of southwest Saskatchewan and the Peck Lake area of west central Saskatchewan. Bonterra continues to acquire exploration lands in the Pembina area of Alberta, is pursuing other drilling opportunities in Alberta and Saskatchewan, and reviews and assesses producing and non-producing properties for acquisitions on an ongoing basis in various areas in Western Canada.

Pembina Area, West Central Alberta

The Pembina field is the largest conventional oil field in Canada and contains our most significant producing property. Our production is predominately predictable, long life, low decline and high quality light oil from the Cardium formation that is located at a depth of approximately 1,550 meters. Bonterra operates approximately 85 percent of its production in this large core area which allows for significant operating efficiencies. The property contains approximately 345 gross (276 net) operated producing wells with an 80 percent average working interest and 137 gross (23.7 net) non-operated producing wells with an approximate 17 percent average working interest.

The Trust's large land holdings and strong infrastructure position provides a strong base to exploit a range of low risk development and exploration opportunities. Even though the Pembina area is considered a mature field it is proving to be a significant area for multi-zone oil and natural gas exploration. The Trust has managed to increase produced reserves in the area through optimization and drilling as well as through key acquisitions.

An ongoing Cardium infill drilling program was initiated on our non-operated properties in 2003. In late 2004 the Trust started an infill drilling program on its operated Cardium properties. Where most operators in the Pembina area are reducing well spacing to 40 acres Bonterra is reducing its spacing to 160 or 80 acres in most areas. The initial 2004 drilling results have been very positive and have provided the Trust with enough information to continue with and expand this program. Bonterra has a significant number of Cardium infill locations that can be drilled to replace existing production and grow its reserves.

Bonterra is also producing from the Belly River formation. The Belly River produces high quality light sweet oil from a depth of approximately 1,100 meters. There is potential to increase production from the Belly River formations through drilling in select areas of the field.

Bonterra has been able to increase natural gas production and reserves by drilling multi-zone shallow gas wells into the Edmonton and Paskapoo formations. The Trust is targeting several productive sands that range in depth from 275 to 750 meters. Bonterra will continue to build on its previous exploration success in the area and develop these low cost shallow natural gas reserves.

Bonterra has been assessing production of coal-bed methane (CBM) in this area for a period of three years with encouraging initial results. Based on the initial results Bonterra had hoped to proceed with a program of re-entering existing wells and drilling new wells to further assess the CBM potential. Due to regulatory delays and uncertainty, Bonterra has delayed this project until all regulatory concerns are rectified. It is anticipated that these concerns will be resolved in Q2, 2005. Bonterra has extensive prospective land holdings near existing operated infrastructure in the area. CBM has the potential to add significant low risk production and reserves and the Trust will continue to pursue this opportunity.

Dodsland Area, Southwest Saskatchewan

The Dodsland properties produce light sweet gravity oil and solution gas from the Viking formation at a depth of approximately 700 meters. Bonterra now operates approximately 425 gross (374 net) wells with an average working interest of 88 percent.

This is low rate stable production so cost control and hedge programs are important focuses of our operating strategy in this area. The Trust is continually reviewing different operating practices and improved technology that may improve the profitability of the property. Bonterra does not have an abandonment or reclamation liability for this property because under terms of an agreement Bonterra has an option to transfer uneconomic wells to the previous owner of the property.

Southeast Saskatchewan

The southeast properties produce slightly sour high gravity oil and solution gas from the Midale formation. The Trust has an average working interest of approximately 98 percent of its properties in the area. Bonterra continues to evaluate this area to determine if further optimization programs may increase overall profitability of the properties.

Shaunavon Area, Southwest Saskatchewan

This property was acquired in January 2005 (the Novitas acquisition). Bonterra operates this major producing property which consists of 56 producing wells in the Shaunavon area of southwest Saskatchewan where the Company's working interest averages approximately 94 percent. The properties are located in the Whitemud and Chambery fields and produce 22 degree API crude oil from the upper Shaunavon formation located at a depth of approximately 1,500 meters. A portion of the property is being produced under waterflood with the majority of the properties still on primary production. The primary production areas are being monitored on an ongoing basis to determine if water flood programs should be initiated. The wells in the Shaunavon area generally have a very long life and stable low decline production profile after a short period of higher decline when a new well initially commences production.

The Trust is reviewing geological information obtained from development on and near our existing lands and is using it to locate potential exploration or development prospects in the area.

Peck Lake Area, West Central Saskatchewan

This property was also obtained in the Novitas acquisition in January 2005. The Peck Lake property is a 100 percent owned and operated shallow gas property located in west central Saskatchewan with four producing gas wells. The property was brought on production in late November, 2004, and is performing to expectations. The Trust will be looking to expand in this area to maximize the value of its operated infrastructure.

Other

Bonterra has varying interests in other producing and non-producing properties in various other areas of Alberta and Saskatchewan. Most of these properties are long term producers and may provide opportunities for increased interests in the future.

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This report dated March 9, 2005 is a review of the operations, current financial position and outlook for the Trust and should be read in conjunction with the audited financial statements for the year ended December 31, 2004, together with the notes related thereto.

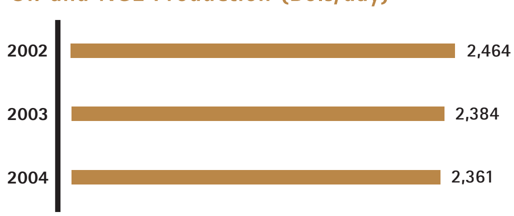
Annual Comparisons

Financial ($000, except $ per unit)	**2004**	2003 [2]	2002 [2]
Revenue - oil and gas (net of royalties)	**$47,966**	$38,381	$36,424
Funds Flow from Operations [1]	**29,606**	22,228	19,458
Per Unit Basic	**2.08**	1.66	1.50
Per Unit Fully Diluted	**2.03**	1.64	1.50
Net Earnings	**20,366**	14,016	12,474
Per Unit Basic	**1.43**	1.05	0.96
Per Unit Fully Diluted	**1.40**	1.04	0.96
Cash Distributions per Unit	**1.88**	1.55	1.43
Capital Expenditures and Acquisitions	**10,943**	5,691	52,751
Total Assets	**84,989**	77,837	76,417
Outstanding Loans	**3,861**	21,830	18,357
Unitholders' Equity	**54,060**	36,983	41,892
Operations			
Oil and Liquids (barrels per day)	**2,361**	2,384	2,464
Natural Gas (MCF per day)	**4,996**	4,403	4,287

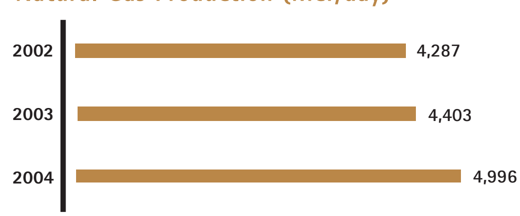
Quarterly Comparisons

	2004			
Financial ($000, except $ per unit)	**4th**	**3rd**	**2nd**	**1st**
Revenue - oil and gas (net of royalties)	**$13,166**	**$12,790**	**$11,223**	**$10,787**
Funds Flow from Operations [1]	**8,678**	**7,499**	**6,936**	**6,493**
Per Unit Basic	**0.57**	**0.52**	**0.51**	**0.48**
Per Unit Fully Diluted	**0.56**	**0.50**	**0.50**	**0.47**
Net Earnings	**6,389**	**5,393**	**4,336**	**4,248**
Per Unit Basic	**0.42**	**0.38**	**0.32**	**0.31**
Per Unit Fully Diluted	**0.41**	**0.37**	**0.31**	**0.31**
Cash Distributions	**0.55**	**0.51**	**0.43**	**0.39**
Capital Expenditures and Acquisitions	**6,038**	**1,476**	**832**	**2,597**
Total Assets	**84,989**	**80,811**	**79,804**	**80,540**
Outstanding Loans	**3,861**	**4,995**	**2,781**	**22,070**
Unitholders' Equity	**54,060**	**56,380**	**57,987**	**38,615**
Operations				
Oil and Liquids (barrels per day)	**2,355**	**2,339**	**2,349**	**2,401**
Natural Gas (MCF per day)	**5,478**	**5,214**	**4,643**	**4,641**

Oil and NGL Production (Bbls/day)



Natural Gas Production (Mcf/day)



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Quarterly Comparisons	2003(2)			
Financial ($000, except $ per unit)	4th	3rd	2nd	1st
Revenue - oil and gas (net of royalties)	$ 9,529	$ 9,587	$ 9,310	$ 9,955
Funds Flow from Operations (1)	5,814	5,319	4,907	6,188
Per Unit Basic	0.44	0.39	0.37	0.46
Per Unit Fully Diluted	0.43	0.38	0.37	0.46
Net Earnings	3,502	3,223	3,043	4,248
Per Unit Basic	0.26	0.24	0.23	0.32
Per Unit Fully Diluted	0.25	0.24	0.23	0.32
Cash Distributions	0.36	0.38	0.40	0.41
Capital Expenditures and Acquisitions	2,665	1,453	1,055	518
Total Assets	77,837	77,429	77,780	77,136
Outstanding Loans	21,830	21,642	20,960	18,792
Unitholders' Equity	36,983	38,355	40,276	42,722
Operations				
Oil and Liquids (barrels per day)	2,429	2,325	2,382	2,400
Natural Gas (MCF per day)	4,272	4,386	4,297	4,661

(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.

Acquisition of Novitas Energy Ltd.

Effective January 7, 2005, the Trust acquired all of the issued and outstanding shares in Novitas Energy Ltd. (Novitas). The Trust issued 1,335,745 units and paid $769,000 in cash for Novitas. For accounting purposes, Novitas was considered a related party due to having the same directors and officers as the Trust. Given this related party status the acquisition of Novitas will be recorded at the net book value of Novitas immediately prior to the acquisition.

The acquisition of Novitas will add approximately 2,200,000 BOE's of proved plus probable reserves including approximately 1,800,000 proved reserves. Anticipated production from Novitas for 2005 is approximately 600 BOE's per day.

The reserve data set forth below for Novitas is based on an evaluation by Sproule Associates Ltd. (Sproule) dated October 15, 2004 with an effective date of September 30, 2004. The reserves data summarizes the oil, liquids and natural gas reserves of Novitas and the net present value of future net revenue for those reserves using forecast prices and costs. The reserves data conforms with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). The Trust engaged Sproule to provide an evaluation of proved plus probable reserves and no attempt was made to evaluate possible reserves. There is no assurance that forecast prices and cost assumptions will be attained and variances could be material. The reserves data should be read in conjunction with the Reserves Information on page 4 which sets out the cautionary statements that are specifically required by NI 51-101.

Summary of Oil and Gas Reserves as of September 30, 2004

Novitas Energy Ltd.
(Forecast Prices and Costs)

	Reserves					
	Light and Medium Oil		Natural Gas		Natural Gas Liquids	
Reserve Category	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved						
Developed Producing	1,530	1,338	68	67	2	1
Undeveloped	-	-	1,670	1,296	-	-
Total Proved	1,530	1,338	1,738	1,363	2	1
Probable	309	278	982	798	3	2
Total Proved Plus Probable	1,839	1,616	2,720	2,161	5	3

Summary of Net Present Values of Future Net Revenue as of September 30, 2004

Novitas Energy Ltd.
(Forecast Prices and Costs)

	Net Present Value of Future Net Revenue				
	Before and After Income Taxes Discounted at (%/year)				
(M$)	0	5	10	15	20
Reserve Category					
Proved					
Developed Producing	12,528	10,160	8,648	7,611	6,856
Undeveloped	3,486	2,938	2,531	2,219	1,972
Total Proved	16,014	13,098	11,179	9,830	8,828
Probable	4,297	2,840	2,145	1,748	1,484
Total Proved Plus Probable	20,311	15,938	13,324	11,578	10,312

Commodity prices used in the above calculations of reserves are as follows:

Year	Hardisty Lloyd-Blend 22.3 API (Cdn $ per barrel)	Alberta Gas Reference Price Plantgate (Cdn $ per MCF)	Propane (Cdn $ per barrel)	Butane (Cdn $ per barrel)	Pentane (Cdn $ per barrel)
2004 -3 mo	39.25	6.11	34.27	40.81	56.07
2005	37.39	6.79	31.86	37.93	52.12
2006	35.16	6.23	28.90	32.69	47.28
2007	32.69	5.90	26.72	30.23	43.72
2008	30.75	5.63	24.57	27.79	40.20
2009	28.55	5.35	23.21	26.26	37.98
2010	29.08	5.45	23.56	26.65	38.55
2011	29.62	5.53	23.92	27.06	39.13
2012	30.17	5.63	24.28	27.46	39.72
2013	30.72	5.73	24.65	27.88	40.32
2014	31.28	5.84	25.02	28.30	40.93
2015	31.86	5.95	25.40	28.73	41.55

Crude oil, natural gas and liquid prices escalate at 1.5% per year thereafter.

1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32

Production

The Trust's 2004 average production of oil and natural gas liquids was 2,361 (2003 – 2,384) barrels per day and natural gas production in 2004 averaged 4,996 (2003 – 4,403) MCF per day. Oil production declined by approximately one percent while gas production increased by approximately 13.5 percent. The Trust's fourth quarter production saw increases in both crude oil and natural gas production due to commencement of production from new wells drilled in the spring and summer of 2004.

The Trust's overall annual decline rate is approximately seven percent which the Trust was able to more than offset with its 2004 spring and summer drill programs. The Trust drilled six gross (4.9 net) oil wells and five gross (4.4 net) natural gas wells in late November and December of 2004. None of these wells were on production by the end of 2004. Currently the Trust has three gross (2.4 net) of the oil wells on production. It is anticipated that two (1.8 net) more of the oil wells will be on production by the end of March with the final well requiring further development work prior to production. The natural gas wells are in the process of being completed and tied in with anticipated production from these wells commencing in the second quarter of 2005. Also, as discussed above, the Trust will have approximately 600 additional BOE's per day commencing in January from the Novitas acquisition.

Crude oil development drilling has been completed on two of the Trust's non-operated interests with net production gains in the fourth quarter of approximately 35 barrels per day. Additional drilling is anticipated to be completed on the Trusts non-operated interests in the first quarter of 2005.

Revenue

Gross revenue from petroleum and natural gas sales prior to royalties was $53,585,000 (2003 - $43,449,000). The increase of $10,136,000 was substantially due to increases in the average price received for crude oil and natural gas liquids from $39.65 per barrel in 2003 to $47.30 per barrel in 2004 and from $5.45 per MCF in 2003 to $6.81 per MCF in 2004 for natural gas. During the fourth quarter prices received for crude oil exceeded $50 per barrel.

Over 95 percent of the Trust's crude oil production consists of light sweet crude with nominal quality and transportation adjustments. Natural gas production consists primarily of dry sweet natural gas.

Although the Trust received much higher net commodity prices in 2004 than in 2003, substantial increases in the price of U.S. WTI oil prices and U.S. Nymex natural gas prices were partially offset by the rising Canadian dollar. The negative impact of the rising Canadian dollar on the 2004 funds flow from operations compared to the 2003 funds flow from operations was approximately 28 cents per unit and approximately 26 cents per unit on net earnings.

Gross revenue has been reduced by $2,526,000 (2003 - $3,150,000) due to lower prices received as a result of price hedging. The Trust will continue to assess hedging of future production (see Business Prospects, Risks, and Outlooks) to assist in managing its cash flow. The Trust continues to follow the policy of protecting high cost production with hedges that provide a significant level of profitability and also to provide for a reasonable amount of cash flow protection for development projects. The Trust will however maintain a policy of not hedging more than 50 percent of production to allow it to benefit from any price movements in either crude oil or natural gas.

Commodity price hedges outstanding as of the date of this report are as follows:

Period of Agreement	Commodity	Volume per Day	Index	Price (Cdn.)
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
April 1, 2005 to July 31, 2005	Crude Oil	500 barrels	WTI	$66.56 per barrel
July 1, 2005 to September 30, 2005	Crude Oil	500 barrels	WTI	$50.02 per barrel
October 1, 2005 to December 31, 2005	Crude Oil	500 barrels	WTI	$55.60 per barrel
January 1, 2006 to March 31, 2006	Crude Oil	500 barrels	WTI	$55.12 per barrel
January 1, 2005 to March 31, 2005	Natural Gas	1,500 GJ's	AECO	$6 per GJ floor and $9.50 per GJ ceiling
January 1, 2005 to March 31, 2005	Natural Gas	1,500 GJ's	AECO	$5.70 per GJ floor and $9.00 per GJ ceiling
April 1, 2005 to October 31, 2005	Natural Gas	2,000 GJ's	AECO	$5.50 per GJ floor and $7.75 per GJ ceiling
November 1, 2005 to March 31, 2006	Natural Gas	1,500 GJ's	AECO	$6.00 per GJ floor and $9.45 per GJ ceiling

Royalties

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During 2004 the Trust paid $4,379,000 (2003 - $3,967,000) Crown royalties and $1,240,000 (2003 - $1,098,000) freehold royalties, gross overriding royalties and net carried interests. The majority of the Trust's wells are low productivity wells and therefore have low Crown royalty rates. The Trust's average Crown royalty rate is approximately eight percent (2003 – eight percent) and approximately two percent (2002 – two percent) for other royalties before hedging adjustments. The acquisition of Novitas will result in a slight increase in 2005 in the royalty rate as Novitas' royalty rate is approximately 18 percent of revenue. The Trust is eligible for Alberta Crown royalty rebates for Alberta production from all wells that it drilled on Crown lands and from a small amount from purchased wells.

Production Costs

Production costs totalled $16,438,000 in 2004 compared to $14,110,000 in 2003. On a barrel of oil equivalent (BOE) basis, 2004 operating costs were $14.06 compared to $12.39 for 2003. 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.

Increased maintenance costs of approximately $750,000 associated with the Trust's Dodsland operations resulted in an increase in BOE costs in this area to $25.42 per BOE in 2004 compared to $19.54 per BOE in 2003. Also, additional maintenance costs of approximately $375,000 were incurred on the Trust's Pinto operations. The maintenance programs resulted in a reduction in the production decline in the Dodsland area and an increase in production from the Pinto assets. The balance of the increase in production costs was primarily attributable to inflationary increases in costs of services and supplies.

As discussed above, the Trust's production comes primarily from low productivity wells. These wells generally result in higher operating costs on a per unit-of-production basis as costs such as municipal taxes, surface leases, power, and personnel costs are not variable with production volumes. The Trust is currently examining means of reducing operating costs. The acquisition of Novitas should result in a minor reduction in operating costs per BOE as Novitas' 2004 operating costs averaged $9.81 per BOE. Operating costs in the $12 to $13 per BOE range are expected for 2005. The high operating 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 operating costs.

General and Administrative Expense

General and administrative expenses were $1,287,000 in 2004 compared to $1,372,000 in 2003. On a BOE basis, general and administrative expenses in 2004 averaged $1.10 compared to $1.21 per BOE in 2003. The Trust recorded only a net $20,000 of general and administrative costs in the fourth quarter of 2004 due primarily to a $500,000 increase in fees charged to Novitas in 2004 (see below).

The Trust is managed internally. In addition, the Trust provides administrative services to Comaplex Minerals Corp. (Comaplex) and Novitas, companies that share common directors and management. The fees for the following services are representative of the fair value for the services rendered. Fees for these services are deducted from the Trusts general and administrative expenses.

During 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 income. In addition, the Trust accrued at year end $500,000 representing compensation for additional engineering, accounting and management services rendered to Novitas during 2004. Total receipts during 2004 were $271,000 (2003 - $120,000). Novitas also paid administrative fees on a per well basis to the Trust for the administration of its oil and gas properties. Total amount paid during 2004 was $192,000 (2003 - $148,000). The Trust received a management fee from Comaplex of $240,000 (2003 - $210,000) for management services and office administration.

Interest Expense

Interest expense for the 2004 fiscal year of the Trust was $493,000 (2003 - $894,000). The decrease was primarily due to the reduction in the Trust's debt resulting from Bonterra's public offering which closed on June 30, 2004. The public offering raised $21,450,000 prior to issue costs of $1,178,000. The net proceeds of $20,272,000 were used for capital expenditures and to retire bank debt.

Interest rate charges during the year on the outstanding debt averaged approximately 4.4 (2003 – 4.25) percent. The Trust maintained an average outstanding debt balance of approximately $10,200,000 (2003 - $20,600,000). Total debt as of December 31, 2004 represents less than two months of 2004 annual funds flow. The Trust believes that maintaining debt at less than one year's funds flow (calculated quarterly based on annualized quarterly results) is an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its coal bed methane, shallow gas and infill oil potential without requiring the issuance of trust units.

The Trust's current bank agreements (each operating corporation has its own) provide for a combined $36,900,000 (includes Novitas effective January 7, 2005) of available credit facility. The interest rate charged on all non-BA facility borrowings is bank prime. The Trust's banking arrangements allow it to use Bankers Acceptances (BA's) as part of its loan facility. Interest charges on BA's are generally one third percent lower than that charged on the general loan account. The Trust had $3,750,000 balance owing to Comaplex as of December 31, 2003. The loan was repaid in the first half of 2004. The loan carried an interest rate of Royal Bank of Canada prime less three quarters of a percent.

Unit Based Compensation

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 required the Trust to record a compensation expense over the vesting period of its unit options based on the fair value of the unit options granted to employees, directors and consultants. The fair value of options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted risk free interest rate of 2.87 (2003 – 3.75) percent, expected weighted average volatility of 30 (2003 – 32) percent, expected weighted average life of 3 (2003 – 3.6) years and an annual dividend rate based on the distributions paid to the Unitholders during the year.

The result of applying the above total unit based compensation of $636,000, based on currently issued and outstanding options, is required to be recorded over the years 2002 to 2006. Unit based compensation of $236,000 in 2004, $211,000 in 2003 and $55,000 in 2002 has been recorded to date.

Depletion, Depreciation, Accretion and Dry Hole Costs

The Trust follows the successful efforts method of accounting for petroleum and natural gas exploration and development costs. Under this method, the costs associated with dry holes are charged to operations. For intangible capital costs that result in the addition of reserves, the Trust depletes its oil and natural gas intangible assets using the unit-of-production basis by field. The Trust believes that the successful efforts method of accounting provides a more accurate cost of the producing properties than the alternative measure of full cost accounting.

For tangible assets such as well equipment, a life span of ten years is estimated and the related tangible costs are depreciated at one tenth of original cost per year. The use of a ten year life span instead of calculating depreciation over the life of reserves was determined to be more representative of actual costs of tangible property. Given the Trusts long production life, wells generally require replacement of tangible assets more than once during their life time. Most of the Trust's wells have been producing since the 1960's and are expected to continue to produce for at least another twenty years.

Provisions are made for asset retirement obligations through the recognition of the fair value of obligations associated with the retirement of tangible long-life assets being 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.

At December 31, 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 five percent. The discount rate is reviewed annually and adjusted if considered necessary. A change in the rate would have a significant impact on the amount recorded for asset retirement obligations.

The calculation of the above requires an estimation of the amount of the Trust's petroleum reserves by field. These figures are calculated annually by an independent engineering firm and any adjustments are used to recalculate depletion and asset retirement obligations. This calculation is to a large extent subjective. Reserve adjustments are affected by economic assumptions as well as estimates of petroleum products in place and methods of recovering those reserves. To the extent reserves are increased or decreased, depletion costs will vary.

For the fiscal year ending December 31, 2004, the Trust expensed $8,392,000 (2003 - $8,024,000) for the above-described items. The increase of $368,000 over the 2003 balance is due primarily to dry hole costs. During the fourth quarter, two gross (1.8 net) natural gas wells were considered to be dry holes. The costs of

$480,000 related to the drilling of those wells have been expensed as dry hole costs and are included in the above depletion figure.

The Trust currently has an estimated reserve life for its proved developed producing reserves of 12.4 (2003 – 11.8) years calculated using the Trust’s gross reserves (prior to allowance for royalties) based on the third party engineering report dated December 31, 2004 and using fourth quarter 2004 average production rates. When taking into consideration the Novitas acquisition, which was effective January 7, 2005, the Trust has an estimated proved developed producing reserve life of approximately 12.1 years after adjusting for the commencement of production from Novitas’ Peck Lake property which reserves were classified as proved non-producing as of the September 30, 2004 Sproule Report.

Income Taxes

Taxable income earned within the Trust is required to be allocated to its Unitholders and as such the Trust will not incur any current taxes. However, the Trust operates its oil and gas interests through its 100 percent owned subsidiaries Bonterra Energy Corp. (Bonterra Corp.), Comstate Resources Ltd. (Comstate Ltd.), and commencing in 2005, from Novitas. Both Bonterra Corp. and Comstate Ltd. pay the majority of their income to the Trust through interest and royalty payments which are deductible for income tax purposes. For the taxation periods ending prior to 2004, Bonterra Corp. and Comstate Ltd. both paid to the Trust sufficient royalty and interest payments to eliminate all of their taxable income. During 2004, due to timing of capital expenditures and other funds flow factors, Comstate Ltd. was unable to pay sufficient payments to the Trust to eliminate all of its taxable income. Given the current development programs in place it is anticipated that Comstate Ltd. will be able to obtain a full refund of the 2004 tax liability of $560,000 in 2005.

Future tax provision relates to the future taxes that exist within Bonterra Corp. and Comstate Ltd. The liability on the balance sheet and the corresponding expense relates to temporary differences existing between Bonterra Corp’s. and Comstate Ltd.’s book value of its assets and its remaining tax pools.

Net Earnings

The Trust is extremely pleased to report net earnings of $20,366,000 for the year ended December 31, 2004. This is an increase of $6,350,000 over the Trusts 2003 net earnings of $14,016,000. The Trust recorded net earnings per unit on a fully diluted basis in 2004 of $1.40 verses $1.04 in the 2003 year. This represents a return on Unitholders’ equity of approximately 37.7 percent during the 2004 year based on year end Unitholders’ equity.

The Trust has an average cost for its oil and gas assets of $4.65 per BOE of proved reserves ($5.11 per BOE including the Novitas acquisition) resulting in a low depletion provision. This low cost combined with low administration and interest expenses all contribute towards the significant net earnings.

Funds Flow from Operations

Funds flow from operations for the year ending December 31, 2004 was $29,606,000 compared to $22,228,000 for the year ended December 31, 2003. Funds flow from operations is not a recognized measure under Canadian generally accepted accounting principles (GAAP). The Trust 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 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.

The increase was primarily due to higher commodity prices and moderately higher production volumes. As with all oil and gas producers the Trust's funds flow is highly dependent on commodity prices. International events and control of crude oil production by OPEC are likely factors that will result in 2005 commodity prices being high and having a positive impact on funds flow.

The following reconciliation compares funds flow to the Trust's net earnings as calculated according to GAAP:

	Three Months		Twelve Months	
For the periods ended December 31	**2004**	2003	**2004**	2003
Net earnings for the period	**$6,389,000**	$3,502,000	**$20,366,000**	$14,016,000
Unit based compensation	**41,000**	31,000	**236,00**	211,000
Dry hole costs	**480,000**	-	**480,000**	-
Depletion, depreciation and accretion	**1,846,000**	2,406,000	**7,912,000**	8,024,000
Future income taxes	**(78,000)**	(125,000)	**612,000**	(23,000)
Funds flow from operations	**$8,678,000**	$5,814,000	**$29,606,000**	$22,228,000

Cash Netback

The following table illustrates the Trust's cash netback:

$ per Barrel of Oil Equivalent (BOE)	**2004**	2003
Production volumes (BOE)	**1,168,993**	1,137,997
Gross production revenue	**$ 45.83**	$ 38.18
Royalties	**(4.79)**	(4.26)
Field operating	**(14.06)**	(12.50)
Field netback	**26.98**	21.42
General and administrative	**(1.10)**	(1.21)
Interest and taxes	**(0.90)**	(0.81)
Cash netback	**$ 24.98**	$ 19.40

Due to the Trust's low royalty rate, the average increase of 20 percent in the gross production revenue resulted in a 28.8 percent increase in the Trust's cash net back.

Liquidity and Capital Resources

During 2004 the Trust participated in drilling 43 gross (27.2 net) wells at a total cost of $10,055,000. Of these wells, 13 gross (.9 net) oil wells and 15 gross (13.6 net) natural gas wells were completed and on production during 2004. In addition, five gross (4.2 net) oil wells will be on production by the end of the first quarter 2005. It is anticipated that the majority of the wells drilled in 2004 will be on production by the end of the second quarter of 2005.

The Trust currently has plans to drill or recomplete 40 net shallow gas wells and 10 net infill oil wells in 2005. Bonterra has been granted approval for reduced drill spacing units with respect to its CBM development. 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. Total capital costs of approximately $18,000,000 for the currently planned development programs are anticipated to be funded out of current cash flow and existing lines of credit.

The Trust is continuing in its efforts to acquire existing production through either property or corporate acquisitions. Acquisitions are being examined with the underlying consideration being to enchance value to our existing Unitholders.

The Trust has no contractual obligations that last more than a year other than its office lease agreement which is as follows:

Contract Obligations	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Office lease	$346,000	$260,000	$86,000	-	-

At December 31, 2004 the Trust had debt of $3,861,000 (2003 – $21,830,000). The Trust through its operating subsidiaries has bank revolving credit facilities totalling $32,000,000 at December 31, 2004 (December 31, 2003 - $32,000,000). The facilities have been increased to $36,900,000 upon the acquisition of Novitas. The facilities carry an interest rate of Canadian chartered bank prime. As of December 31, 2004, the Trust had an outstanding balance under the facilities of $3,550,000 (December 31, 2003 - $17,466,000).

The terms of the credit facilities provide that the loans are due on demand and are subject to annual review. The credit facilities have no fixed payment requirements. The amount available for borrowing under the credit facilities is reduced by the amount of outstanding letters of credit. As at December 31, 2004, the Trust had a nominal amount of outstanding letters of credit. Collateral for the loans consists of a demand debenture providing a first floating charge over all of the Trust's assets, and a general security agreement.

Included in the Trust's 2003 year end debt was a balance payable to Comaplex of $3,750,000. The loan was repaid during the first half of 2004. The interest rate charged on the outstanding balance was bank prime less three-quarters of a percent. The security provided by the Trust for the loan was that the Trust had agreed to maintain a line of credit with its principal banker sufficient to repay the loan if demanded.

The Trust is authorized to issue an unlimited number of trust units without nominal or par value. The following outlines changes in the Trust's unit structure over the past two years.

	2004		2003	
Issued	**Number**	**Amount**	Number	Amount
Trust Units				
Balance, beginning of year	**13,521,405**	**$51,763,000**	13,368,405	$50,198,000
Transfer of contributed surplus to Unit capital	**-**	**159,000**	-	35,000
Issued pursuant to public offering	**1,100,000**	**21,450,000**	-	-
Unit issue costs for public offering	**-**	**(1,178,000)**	-	-
Issued pursuant to Trust unit option plan	**322,000**	**3,292,000**	153,000	1,530,000
Balance, end of year	**14,943,405**	**$75,486,000**	13,521,405	$51,763,000

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,323,450 (2003 – 1,323,450) Trust units. The exercise price of each option granted equals the market price of the Trust unit on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term.

A summary of the status of the Trust's unit option plan as of December 31, 2004 and 2003, and changes during the years ended on those dates is presented below:

	2004		2003	
	Options	**Weighted-Average Exercise Price**	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	**937,000**	**$10.96**	963,000	$10.00
Options granted	**10,000**	**15.60**	211,000	14.26
Options exercised	**(322,000)**	**10.22**	(153,000)	10.00
Options cancelled	**(60,000)**	**10.00**	(84,000)	10.00
Outstanding at end of year	**565,000**	**$11.56**	937,000	$10.96
Options exercisable at end of year	**152,000**	**$11.52**	140,000	$10.00

The following table summarizes information about unit options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Number Outstanding At 12/31/04**	**Weighted-Average Remaining Contractual Life**	**Weighted-Average Exercise Price**	**Number Exercisable At 12/31/04**	**Weighted-Average Exercise Price**
$9.70-$10.00	394,500	2.1 years	$ 9.98	107,500	$10.00
$15.20-$15.60	170,500	2.3 years	15.22	44,500	15.20
$9.70-$15.20	565,000	2.1 years	$11.56	152,000	$11.52

Business Prospects, Risks, and Outlooks

The resource industry operates with a great deal of risk. The most significant risks may come from oil and natural gas price swings, the uncertainty of finding new reserves from drilling programs or acquisitions, competition within the industry, and increasing environmental controls and regulations.

The prices received for crude oil are established by world market forces and for natural gas by forces within North America. Fluctuations in pricing can have extremely positive or negative effects on the Trust's cash flow or in the value of its producing and non-producing oil and natural gas properties.

The Trust presently attempts to minimize these risks by pursuing both oil and natural gas activities and operates its oil and natural gas interests in areas which have long life reserves, where it has the technical expertise to enhance production, control operating costs and to increase margins of profit.

The Trust also maintains an active hedging program. Currently the Trust has forward sales agreements in place for approximately 15 percent on a BOE basis of its estimated 2005 production. The Trust uses a combination of fixed price swaps as well as no cost floor and collars to protect against commodity price declines. During 2004 the Trust incurred a net loss on its hedging of $2,526,000 (2003 - $3,150,000).

Sensitivity Analysis

Sensitivity analysis, as estimated for 2005:	**Cash Flow**	**Cash Flow Per Unit** (1)
U.S. $1.00 per barrel	$1,152.000	$0.071
Canadian $0.10 per MCF	$ 253,000	$0.016
Change of Canadian $0.01/U.S. $ exchange rate	$ 568,000	$0.035

(1) In calculating the cash flow per unit, the units issued pursuant to the takeover of Novitas of 1,335,745 have been included along with the ending units outstanding as of December 31, 2004.

Additional Information

Additional information relating to the Trust may be found on SEDAR.COM as well as on the Trust's web site at www.bonterraenergy.com.

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 the 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.

Deloitte & Touche LLP has been appointed by the Unitholders to serve as the Trust's external auditors. They have examined the financial statements and provided their auditors' report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

George F. Fink
President and CEO

Garth E. Schultz
Vice President, Finance and CFO

Auditors' Report

To the Unitholders of Bonterra Energy Income Trust:

We have audited the consolidated balance sheets of Bonterra Energy Income Trust as at December 31, 2004 and 2003 and the consolidated statements of Unitholders' equity, operations and accumulated income, and of cash flows for the years then ended. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as, evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Deloitte & Touche LLP

Calgary, Alberta
March 15, 2005

Chartered Accountants

Bonterra Energy Income Trust

Consolidated Balance Sheets

For the Years Ended December 31

Assets	2004	2003 (Restated See Note 2)
Current		
Accounts receivable	**$ 7,104,000**	$ 4,505,000
Crude oil inventory (Note 2)	**569,000**	662,000
Parts inventory	**391,000**	360,000
Prepaid expenses	**1,040,000**	716,000
Investment in related party (Note 3)	**461,000**	461,000
	9,565,000	6,704,000
Abandonment deposit (Note 4)	**1,522,000**	-
Property and Equipment (Note 5)		
Petroleum and natural gas properties and related equipment	**102,679,000**	92,637,000
Accumulated depletion and depreciation	**(28,777,000)**	(21,504,000)
	73,902,000	71,133,000
	$ 84,989,000	$ 77,837,000
Liabilities		
Current		
Distribution payable	**$ 2,690,000**	$ 1,623,000
Accounts payable and accrued liabilities	**11,962,000**	5,803,000
Debt (Note 6)	**3,861,000**	21,830,000
	18,513,000	29,256,000
Future income tax liability (Note 7)	**997,000**	384,000
Asset retirement obligations (Note 2)	**11,419,000**	11,214,000
	30,929,000	40,854,000
Unitholders' Equity		
Unit capital (Note 8)	**75,486,000**	51,763,000
Contributed surplus (Note 2)	**307,000**	231,000
Accumulated earnings	**51,688,000**	31,322,000
Accumulated cash distributions	**(73,421,000)**	(46,333,000)
	54,060,000	36,983,000
	$ 84,989,000	$ 77,837,000

On behalf of the Board:

Director

Director

Bonterra Energy Income Trust

Consolidated Statements of Unitholders' Equity

For the Years Ended December 31

	2004	2003 (Restated See Note 2)
Unitholders equity, beginning of year (Restated see Note 2)	**$ 36,983,000**	$ 42,003,000
Net earnings for the year	**20,366,000**	14,016,000
Net capital contributions (Note 8)	**23,563,000**	1,530,000
Unit option adjustment	**236,000**	211,000
Cash distributions	**(27,088,000)**	(20,777,000)
Unitholders' Equity, End of Year	**$ 54,060,000**	$ 36,983,000

Bonterra Energy Income Trust

Consolidated Statements of Operations and Accumulated Income

For the Years Ended December 31

	2004	2003 (Restated See Note 2)
Revenue		
Oil and gas sales, net of royalties of $5,619,000 (2003 - $5,065,000)	**$ 47,966,000**	$ 38,381,000
Production costs	**(16,438,000)**	(14,110,000)
Alberta royalty tax credits	**305,000**	224,000
Interest and other	**113,000**	28,000
	31,946,000	24,523,000
Expenses		
General and administrative	**1,287,000**	1,372,000
Interest on debt	**493,000**	894,000
Unit based compensation (Note 2)	**236,000**	211,000
Dry hole costs	**480,000**	-
Depletion, depreciation and accretion	**7,912,000**	8,024,000
	10,408,000	10,501,000
Earnings Before Income Taxes	**21,538,000**	14,022,000
Income taxes (recovery) (Note 7)		
Current	**560,000**	29,000
Future	**612,000**	(23,000)
	1,172,000	6,000
Net Earnings for the Year	**20,366,000**	14,016,000
Accumulated earnings at beginning of year (Restated see Note 2)	**31,322,000**	17,306,000
Accumulated Earnings at End of Year	**$ 51,688,000**	$ 31,322,000
Net Earnings Per Unit - Basic (Note 1)	**$ 1.43**	$ 1.05
Net Earnings Per Unit - Diluted (Note 1)	**$ 1.40**	$ 1.04

Bonterra Energy Income Trust

Consolidated Statements of Cash Flows

For the Years Ended December 31

	2004	2003 (Restated See Note 2)
Operating Activities		
Net earnings for the year	**$ 20,366,000**	$ 14,016,000
Items not affecting cash		
Unit based compensation (Note 2)	**236,000**	211,000
Dry hole costs	**480,000**	-
Depletion, depreciation and accretion	**7,912,000**	8,024,000
Future income taxes	**612,000**	(23,000)
	29,606,000	22,228,000
Changes in non-cash working capital		
Accounts receivable	**(1,750,000)**	368,000
Crude oil inventory	**80,000**	(123,000)
Parts inventory	**(31,000)**	(38,000)
Prepaid expenses	**(324,000)**	(202,000)
Accounts payable and accrued liabilities	**2,236,000**	(824,000)
	211,000	(819,000)
	29,817,000	21,409,000
Financing Activities		
Increase (decrease) in debt	**(17,969,000)**	2,200,000
Proceeds on issuance of units pursuant to public offering	**21,450,000**	-
Unit issue costs	**(1,178,000)**	-
Unit option proceeds	**3,292,000**	1,530,000
Unit distributions	**(26,021,000)**	(20,625,000)
	(20,426,000)	(16,895,000)
Investing Activities		
Property and equipment expenditures	**(10,943,000)**	(5,691,000)
Abandonment deposit (Note 4)	**(1,522,000)**	-
	(12,465,000)	(5,691,000)
Changes in non-cash working capital		
Accounts receivable	**(849,000)**	-
Accounts payable and accrued liabilities	**3,923,000**	1,177,000
	3,074,000	1,177,000
	(9,391,000)	(4,514,000)
Net cash inflow	**-**	-
Cash, beginning of year	**-**	-
Cash, End of Year	$ **-**	$ -
Cash Interest Paid	$ **493,000**	$ 894,000
Cash Taxes Paid	$ **17,000**	$ 12,000

Notes to the Consolidated Financial Statements

For the Years Ended December 31

1. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

These consolidated financial statements include the accounts of Bonterra Energy Income Trust (the "Trust") and its wholly owned subsidiaries Bonterra Energy Corp. and Comstate Resources Ltd.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property and equipment and for asset retirement obligations are based on estimates of petroleum and natural gas reserves and future costs. By their nature, these estimates are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

Inventories

Inventories consist of crude oil as well as materials and supplies which include tubing, rods, motors, pump jacks, bases and miscellaneous parts used in the maintenance of the Trust's tangible equipment. Both crude oil and materials and supplies are valued at the lower of cost or net realizable value. Inventory cost for crude oil is determined based on combined average per barrel operating costs, royalties and depletion and depreciation for the year and net realizable value is determined based on sales price in the month preceding year end.

Investments

Investments are carried at the lower of cost and market value.

Property and Equipment

Petroleum and Natural Gas Properties and Related Equipment

The Trust follows the successful efforts method of accounting for petroleum and natural gas properties and related equipment. Costs of acquiring unproved properties are capitalized. These costs are assessed at least annually and when circumstances change, for impairment. When property is found to contain proved reserves as determined by the Trusts engineers, the related net book value is depleted on the unit-of-production basis, calculated by field. The costs of dry holes and abandoned properties are charged to operations. Geological costs, lease rentals and carrying costs are charged to income as incurred. Costs of drilling exploratory and development wells that result in additions to proved reserves are capitalized and depleted on the unit-of-production basis. Tangible equipment is depreciated on a straight-line basis over ten years.

Furniture, Fixtures and Office Equipment

These assets are recorded at cost and depreciated over a three to ten year period representing their estimated useful lives.

Income Taxes

Income taxes are calculated using the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported by the Trusts subsidiary companies in the consolidated financial statements of the Trust and their respective tax bases, using substantively enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the Unitholders. As the Trust allocates all of its taxable income to the Unitholders in accordance with the Trust Indenture, and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for income tax expense has been made in the Trust. However, the Trust's subsidiaries are subject to taxation on income which is not transferred to the Trust.

In the Trust structure, payments are made between the Trusts operating subsidiaries and the Trust which result in the transferring of taxable income from the operating subsidiaries to individual Unitholders. These payments may reduce future income tax liabilities previously recorded by the operating companies which would be recognized as a recovery of income tax in the period incurred.

Asset Retirement Obligations

The fair value of obligations associated with the retirement of tangible long-life assets are 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.

Trust-Unit-Based Compensation Plan

The Trust has a unit-based compensation plan, which is described in Note 8. The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants.

Revenue Recognition

Revenues associated with sales of petroleum and natural gas are recorded when title passes to the customer.

Hedging

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 assesses the derivative financial instruments for effectiveness as hedges, both at inception and over the term of the instrument. 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. For the twelve months ended December 31, 2004 the Trust recorded a reduction to net revenue of $2,526,000 (2003 - $3,150,000)

Joint Interest Operations

Significant portions of the Trust's oil and gas operations are conducted with other parties and accordingly the financial statements reflect only the Trust's proportionate interest in such activities.

Net Earnings Per Unit

Basic earnings per unit are computed by dividing earnings by the weighted average number of units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if options or warrants to purchase trust units were exercised. The treasury stock method is used to determine the dilutive effect of trust unit options and warrants, whereby proceeds from the exercise of trust unit options or other dilutive instruments are assumed to be used to purchase trust units at the average market price during the period.

The number of trust units used to calculate diluted net earnings per unit for the year ended December 31, 2004 of 14,557,489 (2003 – 13,558,519) included the weighted average number of units outstanding of 14,217,550 (2003 – 13,394,363) plus 339,939 (2003 – 164,156) units related to the dilutive effect of unit options.

2. CHANGES IN SIGNIFICANT ACCOUNTING POLICIES

The accounting policies and methods of application followed in the preparation of the 2004 annual financial statements are the same as those followed in the preparation of the Trust's 2003 annual financial statements except for the following items:

- Unit-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 previously reported amounts for the twelve months ended December 31, 2003 and balances as at December 31, 2003:

	As reported	Restated
Unit based compensation	$ -	$ 211,000
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

Prior to January 1, 2004, the Trust accounted for its future site restoration liability on the unit-of-production basis.

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 previously reported amounts for the twelve months ended December 31, 2003 and balances as at December 31, 2003:

	As reported	Restated
Depletion, depreciation and accretion	$ 8,203,000	$ 8,024,000
Future income tax expense (recovery)	(134,000)	(23,000)
Unit capital	51,172,000	51,763,000
Accumulated earnings (January 1, 2003)	17,786,000	17,811,000
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	384,000

At December 31, 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:

	2004
Asset retirement obligations, December 31, 2003	**$ 11,214,000**
Adjustment to opening asset retirement obligation	**(7,000)**
Liabilities settled during the period	**(352,000)**
Accretion	**560,000**
Asset retirement obligations, December 31, 2004	**$ 11,419,000**

- Crude oil inventory

Effective January 1, 2004 the Trust records 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 previously reported amounts for the twelve months ended December 31, 2003 and balances as at December 31, 2003:

	As reported	Restated
Oil and gas sales, net of royalties	$ 38,377,000	$ 38,381,000
Production costs	14,227,000	14,110,000
Accumulated earnings (January 1, 2003)	17,811,000	17,306,000
Accumulated earnings (December 31, 2003)	31,820,000	31,322,000
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.

The cumulative impact of the above described accounting changes to the year end December 31, 2003 was a decrease in net earnings of $23,000 with no effect on Basic and Diluted Earnings per Trust Unit.

3. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 (December 31, 2003 – 689,682) common shares in Comaplex Minerals Corp (Comaplex), a company with common directors and management. The investment is recorded at cost with the fair market value based on the trading price of stock at December 31, 2004 of $2,414,000 (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.

4. ABANDONMENT DEPOSIT

The Trust under the Province of Alberta Regulations provided a cash deposit with the Alberta Energy and Utilities Board for the future abandonment of specific wells. The deposit is refundable based on several conditions including abandonment or reactivation of those inactive wells. The deposit bears interest at Canadian chartered bank prime less approximately 2 percent.

5. PROPERTY AND EQUIPMENT

	2004		2003	
	Cost	**Accumulated Depletion and Depreciation**	Cost	Accumulated Depletion and Depreciation
Undeveloped land	**$ 308,000**	**$ -**	$ 186,000	$ -
Petroleum and natural gas properties and related equipment	**101,661,000**	**28,523,000**	91,775,000	21,311,000
Furniture, equipment and other	**710,000**	**254,000**	676,000	193,000
	$ 102,679,000	**$ 28,777,000**	$ 92,637,000	$ 21,504,000

The Trust completed its acquisition of Novitas Energy Ltd. (Novitas) on January 7, 2005. Please refer to Note 13 for details.

6. DEBT

The Trust has a bank revolving credit facility of $32,000,000 at December 31, 2004 (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. 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.

The credit facility carries an interest rate of Canadian chartered bank prime. As of December 31, 2004, the Trust had an outstanding balance under the facility of $3,550,000 (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 year ended December 31, 2004 for this loan was $455,000 (2003 - $636,000).

7. INCOME TAXES

The Trust has recorded a future income tax liability related to assets and liabilities and related tax accounts held through its 100 percent owned operating subsidiaries. The liability relates to the following temporary differences in those subsidiaries:

	2004	2003
Temporary differences related to assets and liabilities of the subsidiary companies	**$ 1,636,000**	$ 1,141,000
Finance expense in corporate subsidiaries	**(33,000)**	(84,000)
Corporate Tax loss carry forwards in the subsidiary companies	**(606,000)**	(673,000)
	$ 997,000	$ 384,000

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

	2004	2003
Earnings before income taxes	**$ 21,538,000**	$ 14,022,000
Combined federal and provincial income tax rates	**39.00%**	41.14%
Income tax provision calculated using statutory tax rates	**8,400,000**	5,769,000
Increase (decrease) in income taxes resulting from:		
Unit based compensation	**92,000**	87,000
Non-deductible crown royalties	**1,317,000**	1,237,000
Resource allowance	**(2,399,000)**	(1,998,000)
Trust income allocated to Unitholders	**(6,181,000)**	(5,051,000)
Others	**(57,000)**	(38,000)
	$ 1,172,000	$ 6,000

The Trust's subsidiaries have the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

	Rate of Utilization %	Amount
Undepreciated capital costs	20-100	$ 5,431,000
Canadian oil and gas property expenses	10	1,600,000
Canadian development expenses	30	7,260,000
Canadian exploration expenses	100	65,000
Income tax losses	100	1,779,000
Finance expenses	20	98,000
		$16,233,000

The Trust has the following tax pools, which may be used to reduce future taxable income allocated to its Unitholders:

	Rate of Utilization %	Amount
Canadian oil and gas property expenses	10	$ 16,197,000
Finance expenses	20	1,041,000
		$ 17,238,000

8. UNIT CAPITAL

Authorized

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

	2004		2003	
Issued	**Number**	**Amount**	Number	Amount
Trust Units				
Balance, beginning of year	**13,521,405**	**$ 51,763,000**	13,368,405	$ 50,198,000
Transfer of contributed surplus to				
Unit capital	**–**	**159,000**	–	35,000
Issued pursuant to public offering	**1,100,000**	**21,450,000**	–	–
Unit issue costs for public offering	**–**	**(1,178,000)**	–	–
Issued pursuant to Trust unit option plan	**322,000**	**3,292,000**	153,000	1,530,000
Balance, end of year	**14,943,405**	**$ 75,486,000**	13,521,405	$ 51,763,000

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.

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,323,450 (2003 – 1,323,450) trust units. The exercise price of each option granted equals the market price of the trust unit on the date of grant and the option's maximum term is five years. Options vest one-third each year for the first three years of the option term.

A summary of the status of the Trust's unit option plan as of December 31, 2004 and 2003, and changes during the years ended on those dates is presented below:

	2004		2003	
	Options	**Weighted-Average Exercise Price**	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	**937,000**	**$10.96**	963,000	$10.00
Options granted	**10,000**	**15.60**	211,000	14.26
Options exercised	**(322,000)**	**10.22**	(153,000)	10.00
Options cancelled	**(60,000)**	**10.00**	(84,000)	10.00
Outstanding at end of year	**565,000**	**$11.56**	937,000	$10.96
Options exercisable at end of year	**152,000**	**$11.52**	140,000	$10.00

The following table summarizes information about unit options outstanding at December 31, 2004:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/04	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 12/31/04	Weighted-Average Exercise Price
$9.70-$10.00	394,500	2.1 years	$ 9.98	107,500	$10.00
$15.20-$15.60	170,500	2.3 years	15.22	44,500	15.20
$9.70-$15.20	565,000	2.1 years	$11.56	152,000	$11.52

The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. The fair value of options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted risk free interest rate of 2.87 (2003 – 3.75) percent, expected weighted average volatility of 30 (2003 – 32) percent, expected weighted average life of 3 (2003 – 3.6) years and an annual dividend rate based on the distributions paid to the Unitholders during the year.

9. RELATED PARTY TRANSACTIONS

During 2004, the Trust provided a temporary operating loan of up to $1,500,000 to Novitas, a company with common directors and management. The loan was repaid prior to December 31, 2004. The loan had an interest rate of bank prime plus one-half percent. There was 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, could not be terminated as long as the loan remained outstanding. Interest paid on the loan during 2004 was $39,000.

During 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 income. In addition, the Trust accrued $500,000 representing compensation for additional engineering, accounting and management services rendered during 2004. Total receipts during 2004 were $272,000 (2003 - $120,000) and these receipts have been included as a recovery of general and administrative expenses.

Novitas also paid administrative fees on a per well basis to the Trust for the administration of its oil and gas properties. Total amount paid during 2004 was $192,000 (2003 - $148,000). This amount has also been recorded as a recovery of general and administrative expenses.

The Trust received a management fee from Comaplex (see Note 3) of $240,000 (2003 - $210,000) for management services and office administration. This cost has been included as a recovery in general and administrative expenses.

At December 31, 2003 the Trust owed Comaplex $3,750,000 which was repaid in the first half of 2004. Cash interest paid during the twelve months ended December 31, 2004 for this loan was $37,000 (2003 - $257,000)

As at December 31, 2004, the Trust had an accounts receivable from Novitas for $503,000 and an accounts receivable from Comaplex for $45,000 in respect of the above services.

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

10. FINANCIAL INSTRUMENTS

Fair Values

The Trust's financial instruments included in the balance sheet are comprised of accounts receivable and current liabilities, including the revolving demand loan. The fair values of these financial instruments approximate their carrying value due to the short-term maturity of those instruments, except borrowings under bank credit facilities are for short periods with variable interest rates, thus, carrying values approximate fair value.

Credit Risk

Substantially all of the Trust's accounts receivable are due from customers in the oil and gas industry and are subject to normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of associated credit risks.

Interest Rate Risk

The Trust's bank debt is comprised of revolving loans at variable rates of interest, and as such, the Trust is exposed to interest rate risk.

Commodity Price Risk

The nature of the Trust's operations results in exposure to fluctuations in commodity prices and exchange rates. The Trust monitors and when appropriate uses derivative financial instruments to manage its exposure to these risks.

11. COMMITMENTS, CONTINGENCIES AND GUARANTEES

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

Period of Agreement	Commodity	Volume per Day	Index	Price (Cdn.)
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
October 1, 2005 to December 31, 2005	Crude Oil	500 barrels	WTI	$55.60 per barrel
January 1, 2005 to March 31, 2005	Natural Gas	1,500 GJ's	AECO	$6 per GJ floor and $9.50 per GJ ceiling
January 1, 2005 to March 31, 2005	Natural Gas	1,500 GJ's	AECO	$5.70 per GJ floor and $9.00 per GJ ceiling

As at December 31, 2004 the mark to market value of the outstanding commodity hedging transactions was a net liability of $299,000 to the Trust.

The Trust has no contractual obligations that last more than a year other than its office lease agreement which is as follows:

Contract Obligations	Total	Less than 1 year	1 – 3 years	4 – 5 years	After 5 years
Office lease	$346,000	$260,000	$86,000	-	-

12. SUBSEQUENT EVENT- COMMITMENTS

The Trust entered into the following commodity hedging transactions subsequent to December 31, 2004 for a portion of its future production:

Period of Agreement	Commodity	Volume per Day	Index	Price (Cdn.)
January 1, 2006 to March 31, 2006	Crude Oil	500 barrels	WTI	$55.12 per barrel
April 1, 2005 to July 31, 2005	Crude Oil	500 barrels	WTI	$66.56 per barrel
April 1, 2005 to October 31, 2005	Natural Gas	2,000 GJ's	AECO	$5.50 per GJ floor and $7.75 per GJ ceiling
November 1, 2005 to March 31, 2006	Natural Gas	1,500 GJ's	AECO	$6.00 per GJ floor and $9.45 per G ceiling

13. SUBSEQUENT EVENT – ACQUISITION

The Trust entered into an agreement in 2004 to acquire Novitas (see Note 9). On January 6, 2005 in excess of 96 percent of the outstanding common shares of Novitas were tendered to the takeover offer. On January 7, 2005 the Trust took up the shares and acquired the remaining outstanding shares through the compulsory acquisition provisions of the Business Corporation Act of Alberta. Funding for the cash portion of the acquisition came from the Trust's available bank lines.

The acquisition will be accounted for the Novitas carrying values due to the related status of Novitas to the Trust. The net assets of Novitas acquired were as follows:

Net Non-cash Working Capital	$(1,273,000)
Bank Indebtedness	(155,000)
Property and Equipment	16,608,000
Bank loan	(4,443,000)
Future Tax Liability	(3,089,000)
Asset Retirement Obligations	(1,198,000)
	$ 6,450,000

Trust Units Issued	$ 5,456,000
Cash	769,000
Acquisition Costs	225,000
	$ 6,450,000

Trust Information

Board of Directors

G.J. Drummond, Nassau, Bahamas

G.F. Fink, Calgary, Alberta

C.R. Jonsson, Vancouver, British Columbia

F. W. Woodward, Calgary, Alberta

Officers

G.F. Fink – President & Chief Executive Officer

R.M. Jarock – Chief Operating Officer

G.E. Schultz – Vice President, Finance,
Chief Financial Officer, & Secretary

Registrar & Transfer Agent

Olympia Trust Company, Calgary, Alberta

Auditors

Deloitte & Touche LLP, Calgary, Alberta

Solicitors

Parlee McLaws, Calgary, Alberta

Tupper, Jonsson & Yeadon,
Vancouver, British Columbia

Bankers

The Royal Bank of Canada, Calgary, Alberta

Stock Listing

The Toronto Stock Exchange, Toronto, Ontario

Trading symbol: BNE.UN

Web Site

www.bonterraenergy.com

Head Office 901, 1015 – 4th Street SW Calgary, Alberta T2R 1J4 PH 403.262.5307 FX 403.265.7488

Bonterra
Energy Income Trust

901, 1015 – 4TH ST SW
CALGARY, ALBERTA T2R 1J4