Bonterra
Energy Income Trust

2005 ANNUAL REPORT

Bonterra Energy Income Trust

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 Trusts business strategy is to strive to maximize unitholders 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 our unitholders.

NOTICE OF ANNUAL GENERAL MEETING

The Annual General Meeting of Unitholders will be held on Wednesday, May 24, 2006, in the Nakiska room at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 11:00 a.m. (Calgary time).

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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 that 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

		2005		2004
Financial ($000, except $ per share)				
Revenue – oil and gas	**$**	**75,837**	$	53,585
Distributions per Unit		**2.37**		1.88
Funds Flow from Operations[1]		**44,579**		29,606
Per Unit Basic		**2.72**		2.08
Per Unit Fully Diluted		**2.69**		2.03
Net Earnings		**33,468**		20,366
Per Unit Basic		**2.04**		1.43
Per Unit Fully Diluted		**2.01**		1.40
Capital Expenditures and Acquisitions[2]		**56,703**		10,595
Working Capital Deficiency		**21,972**		8,948
Unitholders' Equity		**57,322**		54,060
Units Outstanding (000's)		**16,535**		14,943
Operations				
Oil and Liquids (barrels per day)		**2,713**		2,361
Average Price ($ per barrel)	**$**	**58.30**	$	47.30
Natural Gas (MCF per day)		**5,650**		4,996
Average Price ($ per MCF)	**$**	**8.64**	$	6.81
Total barrels per day (BOE per day) [3]	**$**	**3,655**	$	3,194
Reserves				
Oil and Liquids (barrels in 000's)				
Proved Developed Producing (Gross) [4]		**13,840**		11,956
Proved (Gross)		**15,662**		12,832
Proved plus Probable (Gross)		**19,606**		16,084
Natural Gas (MCF in 000's)				
Proved Developed Producing (Gross)		**17,518**		17,021
Proved (Gross)		**20,473**		18,288
Proved plus Probable (Gross)		**25,582**		21,762
Reserve Life Index (Oil, liquids and natural gas @6:1)[5]				
Proved Developed Producing		**12.1**		12.4
Proved		**13.8**		13.3
Proved and Probable		**17.3**		16.5
Reserves in BOE's per Weighted Average Outstanding Unit				
Proved Developed Producing		**1.02**		1.04
Proved		**1.16**		1.12
Proved and Probable		**1.46**		1.39

(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 excluding gain on sale of property.

(2) Capital expenditures and acquisitions include the purchase of Novitas Energy Ltd. (Novitas) on January 7, 2005. The Trust issued 1,335,753 units at a value of $25 per unit plus paid $769,000 in cash for all of the issued and outstanding common shares of Novitas. For accounting purposes the transaction was recorded at the cost of the Novitas' assets and liabilities due to Novitas being considered a related party to the Trust.

(3) 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.

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

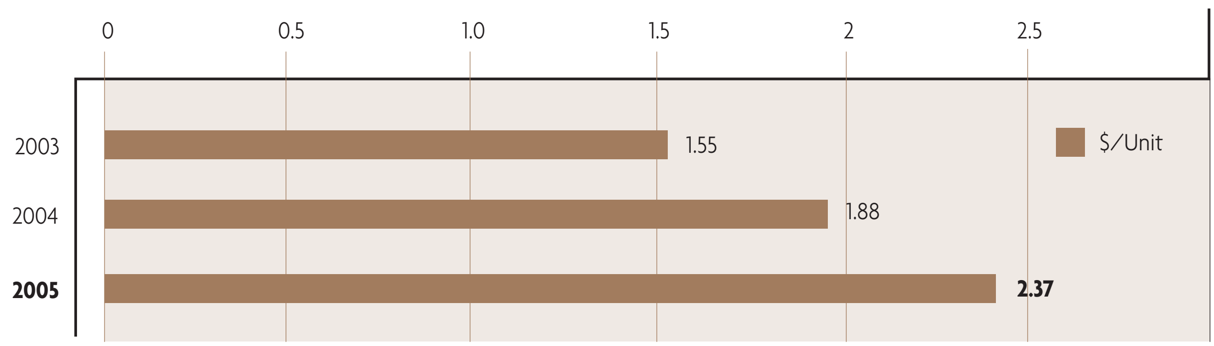
(5) The reserve life index is calculated by dividing the reserves (in BOE's) by the annualized fourth quarter average production rate in BOE/d (2005 – 3,780, 2004 – 3,268).

REPORT TO UNITHOLDERS

Report to Unitholders

Bonterra Energy Income Trust ("Bonterra" or the "Trust") is pleased to report its operational and financial results for the year. It has been a year of growth and success for the Trust. Oil and gas reserves, distributions to Unitholders, net earnings, funds flow, and daily production all increased. There were only two major areas of concern that we encountered in 2005. Firstly, it was a difficult year from a weather perspective and most oil and gas entities could not drill, complete, or tie in new wells or service old wells because of the wet weather; and secondly, it has been difficult to get work done by the service industry due to the demand resulting from the accelerated activity in the oil and natural gas industry.

Bonterra's ability to continue to significantly increase its distributions on an annualized basis is of prime importance to the Trust. A continued above average return to the Trust's investors is an objective that is important. The following graph illustrates the distribution growth during the most recent three year period.



Operations

Bonterra has continued to focus on the development of its properties in the Pembina area, which is located in west central Alberta. Approximately 75 percent of the Trust's production is from this field where production consists of light sweet gravity crude and liquids and sweet natural gas from the Cardium, Belly River, and shallow gas zones.

The life index for the Trust's proved reserves is 13.8 (2004 - 13.3) years, and the life index consisting of proved and probable reserves is 17.3 (2004 – 16.5) years. These reserve life figures are some of the longest (excluding oil sands) in the Trust and Corporate sectors.

The long life index allows the Trust to distribute a higher percentage of its cash flow to Unitholders and for capital expenditures to increase production volumes rather than to maintain production volumes. Bonterra's annual actual decline rate from existing properties is approximately 7 percent.

Production volumes for 2005 averaged 3,655 barrels of oil equivalent (BOE) per day compared to 3,194 BOE per day in 2004. Drill programs during the fourth quarter should assist in increasing production volumes. At the 2005 year-end the Trust had a total of 13 (10.2 net) infill Cardium crude oil wells and 3 (2 net) shallow natural gas wells that had not been tied in and were not on production. The majority of these wells have been tied in and commenced production during the first quarter of 2006.

Bonterra will be able to drill aggressively for many years into the future. If it drills approximately 50 wells per year, the Trust has an inventory of drill locations that exceeds 10 years. This inventory of drill locations is one of the highest in the industry and makes it unnecessary to make acquisitions of producing and non producing properties during periods when costs to make acquisitions are excessively high.

Financial

Bonterra's distribution for 2005 was $2.37 compared to $1.88 for 2004. The Canadian taxable portion in 2005 was 86.05 (2004 – 58.51) percent and 13.95 (2004 – 41.49) percent is a return of capital. With respect to cash distributions paid during the year to U.S. individual Unitholders, 9.3 percent is a return of capital and 90.7 percent should be reported as qualities dividends. High commodity prices generally make it more difficult for Trusts to keep the taxable portion at lower levels.

Revenue from commodity sales was $75,837,000 in 2005 compared to $53,585,000 in 2004. Commodity prices were $58.30 (2004 - $47.30) per barrel of oil and natural gas liquids and $8.64 (2004 - $6.81) per MCF for natural gas.

At year-end Bonterra's net working capital deficit was $21,972,000 (2004 - $8,948,000) when classifying all debt as current liabilities. This debt level represents approximately 5 months of debt to the fourth quarter of 2005 average monthly funds flow. This is a low ratio considering most of Bonterra's capital expenditures in 2005 were incurred in the fourth quarter and did not generate any revenue in 2005 to use to pay down debt incurred for drilling and completions. The Trust's objective is to have debt levels that do not exceed one year's funds flow.

Outlook

The objectives for the Trust are to increase its production volumes and reserves by drilling its large inventory of drill locations in a conservative and timely manner. Subject to reasonably consistent commodity prices, this should enable the Trust to annually increase its distributions on a per Unit basis. Drilling will primarily be conducted in the Pembina field in the Cardium and shallow gas zones including some wells in the Ardley coal beds and experimentation completions in the Horseshoe Canyon coal beds.

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 1998, for every $100 invested at that time, a Unit holder that held continuously from that date to February 28, 2006, would have received $1,902.55 in distributions and have Trust Units worth $5,852.06.

The Board of Directors of the operating company and management wish to thank the Unitholders for their continued loyal support and advice, and also wish to thank the staff for its continued loyalty and the large contribution that is made on a continuous basis towards the success of the Trust.

Submitted on behalf of the Board of Directors

George F. Fink
President, CEO, and Director

REVIEW OF OPERATIONS

Reserves

The Trust engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of December 31, 2005. The reserves are located in the Provinces of Alberta and Saskatchewan. The Trust's main oil producing areas are located in the Pembina area of Alberta, and the Dodsland and Shaunavon areas of Saskatchewan. The gross reserve figure for 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, 2005 (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	13,070	12,407	17,518	13,160	770	549
Developed Non-Producing	357	325	1,257	978	3	2
Undeveloped	1,462	1,335	1,698	1,188	-	-
TOTAL PROVED	14,889	14,067	20,473	15,326	773	551
PROBABLE	3,758	3,580	5,109	3,780	186	133
TOTAL PROVED PLUS PROBABLE	18,647	17,647	25,582	19,106	959	684

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)	Gross Proved Plus Probable (MMcf)
December 31, 2004	11,541	2,936	14,477	18,288	3,473	21,761
Extension	–	–	–	8	–	8
Improved recovery	1,806	637	2,442	2,085	719	2,804
Technical revisions	(42)	(300)	(342)	(481)	(361)	(842)
Discoveries	–	–	–	214	115	329
Acquisitions	1,569	324	1,893	1,854	1,148	3,002
Dispositions	–	–	–	(52)	(82)	(134)
Economic factors	1,008	163	1,171	620	97	716
Production	(993)	–	(993)	(2,063)	–	(2,063)
December 31, 2005	14,889	3,759	18,648	20,473	5,109	25,582

Summary of Net Present Values of Future Net Revenue as of December 31, 2005 (Forecast Prices and Costs)

	Net Present Value of Future Net Revenue Before and After Income Taxes Discounted at (%/year)				
(M$) RESERVE CATEGORY	0	5	10	15	20
PROVED					
Developed Producing	499,982	330,464	251,662	207,080	178,336
Developed Non-Producing	20,664	16,340	14,120	12,639	11,504
Undeveloped	23,212	16,902	12,056	8,286	5,317
TOTAL PROVED	543,858	363,706	277,838	228,005	195,157
PROBABLE	161,186	68,687	40,309	27,876	21,033
TOTAL PROVED PLUS PROBABLE	705,044	432,393	318,147	255,881	216,190

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)
2006	70.07	11.37	39.25	47.01	71.77
2007	70.99	10.63	39.76	47.62	72.71
2008	62.73	8.76	35.14	42.08	64.25
2009	57.53	7.69	32.22	38.59	58.92
2010	54.65	7.39	30.61	36.66	55.97
2011	55.47	7.52	31.07	37.21	56.81
2012	56.31	7.63	31.54	37.77	57.67
2013	57.16	7.77	32.01	38.34	58.54
2014	58.02	7.90	32.50	38.92	59.42
2015	58.89	8.04	32.99	39.51	60.31
2016	59.78	8.18	33.48	40.10	61.22

Crude oil, natural gas and liquid prices escalate at various rates 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 costs 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:

	2005		2004	
	Oil and NGL (Bbls/day)	Natural Gas (MCF/day)	Oil and NGL (Bbls/day)	Natural Gas (MCF/day)
Pembina, Alberta	1,767	4,290	1,729	4,231
Shaunavon, Saskatchewan	363	-	-	-
Dodsland, Saskatchewan	302	151	388	207
Peck Lake, Saskatchewan	-	541	-	-
Pinto, Saskatchewan	73	86	59	50
Redwater, Alberta	37	57	42	53
Midale, Saskatchewan	42	14	42	18
Other	129	511	101	437
	2,713	5,650	2,361	4,996

Land Holdings

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

	2005		2004	
	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	114,657	68,098	113,697	67,159
Saskatchewan	63,136	48,538	32,584	19,524
	177,793	116,636	146,281	86,683

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:

	2005	2004
Acquisitions	$ 40,852,000	$ -
Exploration and development costs	15,810,000	10,057,000
Pipeline projects	15,000	302,000
Land costs	26,000	236,000
Net petroleum and natural gas capital expenditures	$ 56,703,000	$ 10,595,000

Drilling History

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

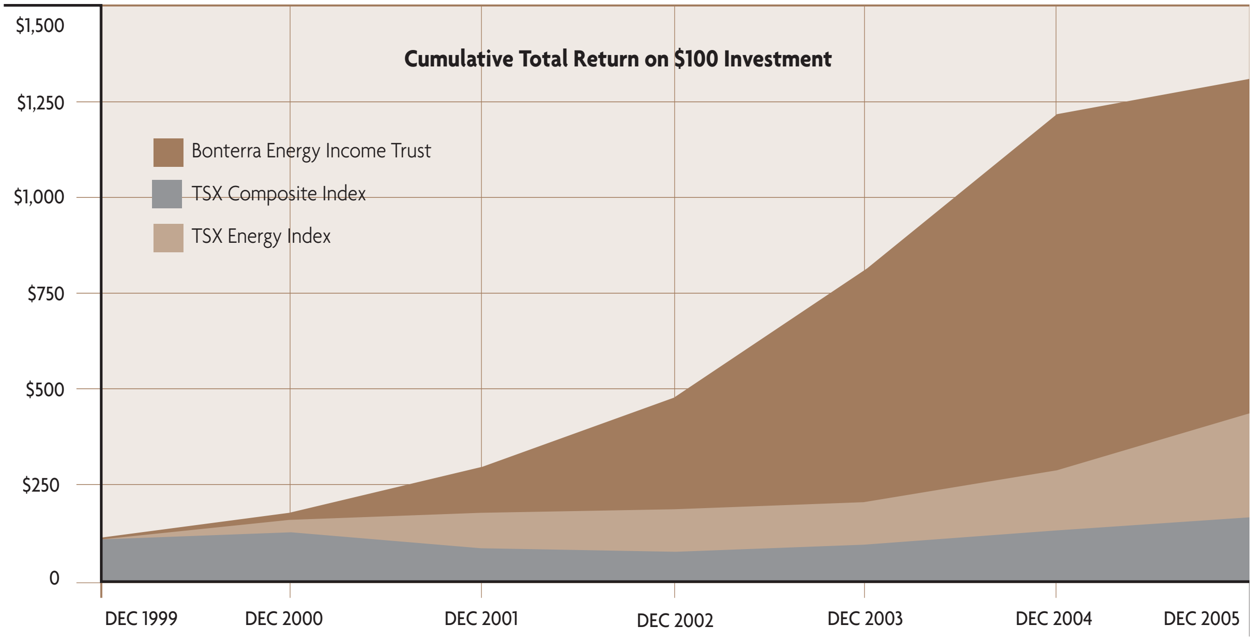
	2005					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	42	15.0	-	-	42	15.0
Natural Gas	6	3.5	-	-	6	3.5
Dry	-	-	-	-	-	-
Total	48	18.5	-	-	48	18.5
Success rate	100%	100%	-	-	100%	100%

	2004					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	19	5.8	-	-	19	5.8
Natural Gas	19	16.6	1	1	20	17.6
Dry	4	3.8	-	-	4	3.8
Total	42	26.2	1	1	43	27.2
Success rate	90.5%	85.5%	100%	100%	90.7%	86.0%

	2003					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	31	3.3	-	-	31	3.3
Natural Gas	3	3.0	6	5.8	9	8.8
Dry	-	-	-	-	-	-
Total	34	6.3	6	5.8	40	12.1
Success rate	100%	100%	100%	100%	100%	100%

Market Performance

The following graph illustrates changes over the past six 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 1999	Dec 2000	Dec 2001	Dec 2002	Dec 2003	Dec 2004	**Dec 2005**
Bonterra Energy Income Trust(1)	$100	$164	$275	$481	$780	$1,242	**$1,277**
TSX Composite Index	$100	$107	$92	$79	$98	$111	**$135**
TSX Energy Index	$100	$146	$149	$168	$207	$267	**$426**

Note 1: Includes distributions of $8.03 per Unit since becoming a Trust.

Trust Unit Trading Statistics

Unit Prices (based on daily closing price)	2005	2004
High	$25.97	$26.00
Low	$20.00	$15.15
Close	$23.60	$25.10
Daily Average Trading Volume	26,487	22,918

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. The Trust's producing properties are located in the Pembina area of Alberta, the East Central area of Alberta, the Dodsland and Shaunavon areas in southwest Saskatchewan, and the southeast area of Saskatchewan. In 2005 Bonterra added quality properties in the Shaunavon area of southwest Saskatchewan and the Peck Lake area of west central Saskatchewan. Bonterra's reserves and production growth will come primarily from internally generated exploitation and drilling programs with predictable results on existing properties. The Trust will continue to acquire exploration and development lands in the Pembina area of Alberta, and pursue other drilling opportunities in Alberta and Saskatchewan. The Trust will be reviewing and assessing strategic 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 the Trust's most significant producing property. Pembina is Bonterra's largest core area representing 77.8% of the Trust's total reserves. This 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 87 percent of its production which allows for significant operating efficiencies. The property contains approximately 360 gross (290 net) operated producing wells with an 80 percent average working interest and 145 gross (24 net) non-operated producing wells with an approximate 17 percent average working interest.

This large land holding 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 with predictable results. The Trust has managed to increase reserves in the area through optimization and drilling as well as through key acquisitions. As a result, Bonterra has one of the longest Reserve Life Index's and a proven record of production and reserves replacement through drilling and revisions.

The Trust's large drilling inventory has enabled it to increase production volumes. A Cardium infill drilling program was initiated on Bonterra's non-operated properties in 2003 and has continued successfully through 2005. The Trust conducted a small operated Cardium infill program in late 2004 with results that exceeded expectations. An expanded Cardium drilling program was initiated in the fall of 2005 and will continue for a few years. The results of the expanded drilling program met expectations even though there has been a delay in getting a considerable number of wells on production because of poor weather conditions and availability of services.

Bonterra has the potential to significantly increase the value of its Cardium oil from additional infill density drilling and CO2 flooding which will allow growth of its existing asset base. Most operators in the Pembina area have been reducing well spacing to 40 acres; whereas, Bonterra is generally reducing its spacing to 80 acres. There is significant uncertainty over the economic feasibility of enhanced oil recovery using CO2 to increase production from the Cardium formation; however, public information from ongoing pilots is encouraging. The Trust has a large land base that may be suitable for CO2 enhanced oil recovery and will continue to investigate its potential development.

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 850 meters. Bonterra has been able to significantly increase its shallow gas land base in 2005 and will capitalize on this in 2006 with an expanded drilling program. Bonterra expects to build on its previous exploration success and add to its reserve base by developing these low risk shallow gas reserves.

Bonterra has been assessing production of natural gas from coals (NGC) in the Pembina area for a period of four years with encouraging initial results. Based on these results, Bonterra had hoped to proceed with a program of re-entering existing wells and drilling new wells to further assess the NGC potential. Due to regulatory delays and uncertainty by regulators, Bonterra has delayed this project until all regulatory concerns are rectified. Bonterra has extensive prospective land holdings near existing operated infrastructure in the area. NGC 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 the 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 the majority of 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 primarily from the Midale formation. The Trust has an average working interest of approximately 98 percent in the area. Bonterra continues to evaluate this area to determine if further optimization programs may increase overall profitability on the properties. Some of these properties are located close to fields that have extensive CO2 flood programs; and therefore, in the future may be conducive to reserve and production increases from a CO2 flood program.

Shaunavon Area, Southwest Saskatchewan

Bonterra operates this major producing property which consists of 56 producing wells in the Shaunavon area of southwest Saskatchewan where the Trust'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 continuing to assess its undeveloped acreage to determine if there are potential exploration or development prospects in the area.

Peck Lake Area, West Central Saskatchewan

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 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This report dated March 17, 2006 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, 2005, together with the notes related thereto.

Annual Comparisons

	2005	2004	2003
Financial ($000, except $ per unit)			
Revenue - oil and gas	**$ 75.837**	$ 53,585	$ 43,449
Funds Flow from Operations (1)	**44,579**	29,606	22,228
Per Unit Basic	**2.72**	2.08	1.66
Per Unit Fully Diluted	**2.69**	2.03	1.64
Net Earnings	**33,468**	20,366	14,016
Per Unit Basic	**2.04**	1.43	1.05
Per Unit Fully Diluted	**2.01**	1.40	1.04
Cash Distributions per Unit	**2.37**	1.88	1.55
Capital Expenditures and Acquisitions	**56,703**	10,595	5,691
Total Assets	**110,149**	84,989	77,837
Working Capital Deficiency	**21,972**	8,948	22,552
Unitholders' Equity	**57,322**	54,060	36,983
Operations			
Oil and Liquids (barrels per day)	**2,713**	2,361	2,384
Natural Gas (MCF per day)	**5,650**	4,996	4,403

Quarterly Comparisons

	2005			
	4th	3rd	2nd	1st
Financial ($000, except $ per unit)				
Revenue - oil and gas	$ 21,753	$ 20,532	$ 17,114	$ 16,438
Funds Flow from Operations (1)	12,489	12,209	10,167	9,714
Per Unit Basic	0.76	0.75	0.62	0.59
Per Unit Fully Diluted	0.76	0.74	0.61	0.58
Net Earnings	9,918	9,309	7,115	7,126
Per Unit Basic	0.59	0.57	0.44	0.44
Per Unit Fully Diluted	0.58	0.56	0.43	0.43
Cash Distributions	0.68	0.60	0.55	0.54
Capital Expenditures and Acquisitions	10,979	3,022	678	42,024
Total Assets	110,149	101,008	99,914	102,088
Working Capital Deficiency	21,972	10,920	11,379	11,896
Unitholders' Equity	57,322	60,662	60,467	61,985
Operations				
Oil and Liquids (barrels per day)	2,814	2,680	2,635	2,724
Natural Gas (MCF per day)	5,795	5,692	5,462	5,649

	2004			
	4th	3rd	2nd	1st
Financial ($000, except $ per unit)				
Revenue - oil and gas	$ 14,774	$ 14,244	$ 12,536	$ 12,031
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	5,690	1,476	832	2,597
Total Assets	84,989	80,811	79,804	80,540
Working Capital Deficiency	8,948	4,995	2,781	21,384
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

(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 excluding gain on sale of property.

Officers Certification of Evaluation of Disclosure Controls

The Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of the Trust's disclosure controls and procedures as of December 31, 2005 and have concluded that such disclosure controls were effective to provide reasonable assurance that material information relating to the Trust or its subsidiaries is made known to them.

Production

The Trust's 2005 average production of oil and natural gas liquids was 2,713 (2004 – 2,361) barrels per day and natural gas production in 2005 averaged 5,650 (2004 – 4,996) MCF per day. Oil production increased by approximately 15 percent while gas production increased by approximately 13 percent. The increases were predominantly due to the Novitas Energy Ltd. (Novitas) acquisition on January 7, 2005. 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 2005.

The Trust's overall annual decline rate for 2005 is approximately seven percent which the Trust was able to offset with its 2004 fall drill program. The Trust drilled six gross (4.9 net) oil wells and five gross (4.4 net) natural gas wells in November and December of 2004. Of these wells two (2 net) gas wells were dry holes and one oil well (1 net) was not tied-in until the first quarter of 2006.

In August 2005 the Trust commenced with its oil infill drill program. The program which was originally planned to commence in May was delayed due to wet spring and summer weather as well as delays in obtaining a drilling rig. The Trust drilled a total of 15 (12.2 net) infill crude oil wells prior to year end. Of these wells only two were tied in and on production prior to year end. It is anticipated that the majority of the remaining wells will be tied-in and on production by the end of the first quarter of 2006.

Five (2.5 net) natural gas wells were drilled by the Trust during July and one (1 net) in September. Three (1.5 net) of these wells were on production in the fourth quarter of 2005. The balance of the wells are anticipated to be on production prior to the end of the first quarter of 2006.

Crude oil development drilling was also conducted on three of the Trust's non-operated property interests with net production gains in the fourth quarter of approximately 70 barrels per day. Additional drilling is anticipated to be completed on the Trusts non-operated interests in the first quarter of 2006.

Revenue

Gross revenue from petroleum and natural gas sales prior to royalties was $75,837,000 (2004 - $53,585,000). The increase of $22,252,000 was due to increased production volumes from the acquisition of Novitas and substantial increases in the average price received for crude oil and natural gas. The price received for crude oil increased to $58.30 per barrel in 2005 from $47.30 per barrel in 2004 and natural gas prices increased to $8.64 per MCF in 2005 from $6.81 per MCF in 2004.

The increase in Q4 gross revenues of $1,221,000 over Q3 was due primarily to increased production volumes arising from the Trust's operated and its partner's non-operated fall drill programs. The average price received in the fourth quarter for crude oil and natural gas liquids was $60.73 ($64.48 third quarter) per barrel and $11.16 ($8.69 third quarter) per MCF for natural gas.

Although the Trust received higher net commodity prices in 2005 than in 2004, 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 2005 funds flow from operations was approximately 29 cents per unit and approximately 29 cents per unit on net earnings.

Gross revenue has been reduced by $4,054,000 (2004 - $2,526,000) due to lower prices received as a result of price hedging. The Trust will continue to hedge 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, 2006 to March 31, 2006	Crude Oil	500 barrels	WTI	$55.12 per barrel
April 1, 2006 to June 30, 2006	Crude Oil	500 barrels	WTI	$65.07 per barrel
July 1, 2006 to September 30, 2006	Crude Oil	500 barrels	WTI	Floor of $65.00 and ceiling of $77.52 per barrel
October 1, 2006 to December 31, 2006	Crude Oil	500 barrels	WTI	Floor of $70.00 per barrel and ceiling of $80.10 per barrel
May 1, 2005 to March 31, 2006	Natural Gas	2,000 GJ's	AECO	Floor of $6.75 per GJ (May 1, 2005 to October 31, 2005) and ceiling of $12.25 per GJ (November 1, 2005 to March 31, 2006)
November 1, 2005 to March 31, 2006	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $9.45 per GJ
April 1, 2006 to October 31, 2006	Natural Gas	2,000 GJ's	AECO	Floor of $8.55 and Ceiling of $14.00 per GJ

Royalties

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During 2005 the Trust paid $6,986,000 (2004 - $4,379,000) in Crown royalties and $2,009,000 (2004 - $1,240,000) in 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 nine percent (2004 – eight percent) and approximately three percent (2004 – two percent) for other royalties before hedging adjustments. The acquisition of Novitas resulted in a slight increase in the 2005 royalty rates. 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 of purchased wells.

Gain on Sale of Property

On April 8, 2005, a former subsidiary of Novitas, Pine Cliff Energy Ltd.'s (Pine Cliff) (with common directors and management with Bonterra) rights offering closed with over 97 percent of former Novitas shareholders exercising their rights to acquire common shares in Pine Cliff for $0.15 per common share. As part of the rights offering, the Trust agreed to sell to Pine Cliff effective January 1, 2005 (closing April 8, 2005) approximately 18 BOE per day of production and some exploration lands formerly held by Novitas for proceeds of approximately $1,000,000. As a result of this sale the Trust reported a gain on sale of property of $225,000. The balance of the gain of $38,000 relates to a disposition of an interest in another non-core area property.

Production Costs

Production costs totalled $20,203,000 in 2005 compared to $16,438,000 in 2004. On a barrel of oil equivalent (BOE) basis 2005 operating costs were $15.14 compared to $14.06 for 2004. 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.

The increases in operating costs were primarily due to four factors. Firstly the acquisition of Novitas resulted in approximately $2,000,000 of additional costs. Secondly, during 2005 the Trust settled a 2000 to 2003 natural gas processing fee adjustment with the operator of several of the Trust's natural gas processing plants. This adjustment resulted in approximately $600,000 of additional processing fees being charged to operations in 2005. Thirdly, a pipeline spill in March which resulted in an additional $100,000 (net of insurance claim) of operating costs. Finally costs of goods and services in the petroleum sector increased significantly over the past 12 months.

Operating costs were $5,541,000 in the fourth quarter of 2005 compared to $5,038,000 in the third quarter. The increase was due to a $150,000 (net to the Trust) property tax adjustment in relation to a non-operated property, additional costs related to winter road maintenance and significant increases of up to 20 percent in service rig and other operating costs.

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 lease, power and personnel costs are not variable with production volumes. The Trust is continually examining means of reducing operating costs. Operating costs in the $13 to $14 per BOE range are expected for 2006. The high operating costs for the Trust are substantially offset by low royalty rates of approximately 11 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 $2,420,000 in 2005 compared to $1,287,000 in 2004. On a BOE basis, general and administrative expenses in 2005 averaged $1.81 compared to $1.10 per BOE in 2004. The Trust is managed internally. In addition, the Trust provides administrative services to Comaplex Minerals Corp. (Comaplex) and Pine Cliff, companies that share common directors and management. The Trust received a management fee from Comaplex of $240,000 (2004 - $240,000) and $132,000 from Pine Cliff for management services and office administration. The fees for the 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 (prior to the takeover), the Trust received a management fee from Novitas for management services of $20,000 per month plus five percent of before tax income. In addition, the Trust accrued $500,000 at the 2004 year end representing compensation for additional engineering, accounting and management services rendered to Novitas during 2004 and prior years. These fees resulted in a reduction of over $750,000 in the Trusts 2004 administration costs.

The Trust has an employee incentive plan equal to three percent of net earnings before taxes. In 2005 net earnings before taxes increased to $33,548,000 from $21,538,000 in 2004 resulting in an additional $370,000 of employee compensation expense.

The fourth quarter general and administrative expenses were $177,000 lower than the third quarter. The decrease was primarily due to incurring several one time costs in the third quarter for third party consulting fees. In addition, historically the third quarter is the highest quarter for general and administrative costs as several reoccurring costs for general office expense items are incurred in the third quarter.

Interest Expense

Interest expense for the 2005 fiscal year for the Trust was $575,000 (2004 - $493,000). The increase was due to increased loan balances resulting from the Novitas acquisition. Interest rate charges during the year on the outstanding debt averaged approximately 4.7 (2004 – 4.8) percent. The Trust maintained an average outstanding debt balance of approximately $12,250,000 (2004 - $10,200,000). Total debt as of December 31, 2005 represents less than six months of 2005 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 infill oil, shallow gas and natural gas from coals potential without requiring the issuance of trust units.

The Trust's current bank agreements (each of Bonterra Energy Corp, Comstate Resources Ltd. and Novitas have their own) provide for a combined $36,900,000 of available credit facility. The interest rate charged on all non Banker Acceptances (BA's) facility borrowings is bank prime. The Trust's banking arrangements allow it to use 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.

Unit Based Compensation

The Trust is required 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. During the year 407,000 unit options were granted. The fair value of options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted risk free interest rate of 3.47 (2004 – 2.87) percent, expected weighted average volatility of 31 (2004 – 30) percent, expected weighted average life of 2.5 (2004 – 3) years and an annual dividend rate based on the distributions paid to the Unitholders during the year.

The result of applying the above, a total unit based compensation of $1,023,000, based on currently issued and outstanding options, is required to be recorded over the years 2005 to 2007. Of the above amount, unit based compensation of $498,000 was recorded in 2005.

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 Trust's 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, 2005, the estimated total undiscounted amount required to settle the asset retirement obligations was $39,921,000 (2004 - $28,360,000). Of the $11,561,000 increase, $4.2 million is due to the Novitas acquisition and approximately $1 million due to the buyout of an operating contract with an operator in the Dodsland area of Saskatchewan whereby the operator no longer is required to pay for the abandonment of wells. The remaining increase is due to additional wells (see production) and increased cost estimates for abandonment.

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. Based on the current provision, a one percent increase in the risk adjusted rate would decrease the asset retirement obligation by $1,990,000. While a one percent decrease in the risk adjusted rate would increase the asset retirement obligation by $2,600,000.

The above calculation requires an estimation of the amount of the Trust's petroleum reserves by field. This figure is 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, 2005, the Trust expensed $10,358,000 (2004 - $8,392,000) for the above-described items. The increase of $1,966,000 over the 2004 balance is due primarily to the Novitas acquisition ($1,793,000). The entire dry hole cost of $628,000 relates to wells that were drilled in 2004 but were not determined to be dry holes until the third quarter of 2005. The delay in determining the status of the wells was due to examining whether the wells had coal-bed methane or other shallow gas productive zones which would provide sufficient production to make the wells economic.

The Trust currently has an estimated reserve life for its proved developed producing reserves of 12.1 (2004 – 12.4) years calculated using the Trust's gross reserves (prior to allowance for royalties) based on the third party engineering report dated December 31, 2005 and using fourth quarter 2005 average production rates. Based on total proved reserves the Trust has a 13.8 (2004 – 13.3) year reserve life and if proved and probable are used the reserve life increases to 17.3 (2004 – 16.5) years. These figures are some of the longest (excluding oil sands) reserve life indexes in the Trust sector.

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 Novitas. All operating companies 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 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 and paid taxes of approximately $560,000. Comstate Ltd. was able to obtain a full refund of the 2004 taxes in 2005.

The Province of Saskatchewan levies a resource surcharge on all oil and gas produced in the province. This surcharge applies if an individual company exceeds a minimum capital threshold or where there are related companies a combined asset threshold also applies. During 2005, Bonterra Corp. exceeded the individual company threshold in the third quarter of 2005 and is now subject to the surcharge. The Trust recorded a tax expense of $347,000 in relation to the surcharge. It is anticipated that Comstate Ltd. will exceed the individual company limit in 2006 and Novitas will be subject to the surcharge by 2007 due to the continued combined growth of the Trust's subsidiaries. Based on the Trust's 2005 revenues, from oil and gas production in the Province of Saskatchewan, and if all operating companies had exceeded the combined asset threshold a total tax expense of $675,000 would have been recorded.

Future tax provision relates to the future taxes that exist within Bonterra Corp., Comstate Ltd. and Novitas. The liability on the balance sheet and the corresponding income recovery relates to temporary differences existing between Bonterra Corp's., Comstate Ltd.'s and Novitas' book value of its assets and its remaining tax pools. Provision for future tax fluctuates quarter over quarter depending on the timing of capital expenditures and funds flow levels in each respective operating company.

Net Earnings

The Trust's net earnings of $33,468,000 for the year ended December 31, 2005 represents a substantial increase of $13,102,000 over the Trusts 2004 net earnings of $20,366,000. The Trust recorded net earnings per unit on a fully diluted bases in 2005 of $2.04 verses $1.40 in the 2004 year. This represents a return on Unitholders' equity of approximately 58.4 (2004 - 37.7) percent based on year end Unitholders' equity.

The Trust has an average cost for its oil and gas assets of $5.08 per BOE of proved reserves resulting in a low depletion provision. This low cost combined with moderate 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, 2005 was $44,579,000 compared to $29,606,000 for the year ended December 31, 2004. Funds flow from operations is not a recognized measure under 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 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 excluding gain on sale of property.

The increase was primarily due to higher commodity prices and 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 2006 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 Canadian generally accepted accounting principles:

	Three Months		**Twelve Months**	
For the periods ended December 31	2005	2004	2005	2004
Net earnings for the period	$ 9,918,000	$ 6,389,000	$33,468,000	$20,366,000
Unit based compensation	145,000	41,000	498,000	236,000
Dry hole costs	11,000	480,000	628,000	480,000
Depletion, depreciation and accretion	2,395,000	1,846,000	9,730,000	7,912,000
Future income taxes	20,000	(78,000)	255,000	612,000
Funds flow from operations	$12,489,000	$ 8,678,000	$44,579,000	$29,606,000

Cash Netback

The following table illustrates the Trust's cash netback:

$ per Barrel of Oil Equivalent (BOE)	2005	2004
Production volumes (BOE)	1,334,075	1,168,993
Gross production revenue	$ 56.85	$ 45.83
Royalties	(6.74)	(4.79)
Field operating	(15.14)	(14.06)
Field netback	34.97	26.98
General and administrative	(1.81)	(1.10)
Interest and taxes	(0.30)	(0.90)
Cash netback	$ 32.86	$ 24.98

Due to the Trust's low royalty rate, the average increase of 24 percent in the gross production revenue resulted in a 31.5 percent increase in the Trust's cash netback.

Liquidity and Capital Resources

During 2005 the Trust participated in drilling 48 gross (18.5 net) wells at a total cost of $15,810,000. Of these wells, 42 gross (15 net) were oil wells and 6 gross (3.5 net) were natural gas wells. The Trust's operated 2005 drill program consisted of 15 gross (12.2 net) Cardium oil wells and 6 gross (3.5 net) natural gas wells.

Only two (2 net) oil wells drilled by the Trust were tied in and on production prior to year end. The majority of the remaining wells will be tied-in and on production by the end of the first quarter of 2006. Approximately one-third of the non-operated crude oil wells were on production by year end. Three (1.5 net) of the natural gas wells were on production in the fourth quarter of 2005. The balance of the wells are anticipated to be on production prior to the end of the first quarter of 2006.

The Trust currently has plans to drill a combined total of 50 gross (37.5 net) infill Cardium, shallow gas and natural gas from coal wells in 2006. Total capital costs of approximately $21,600,000 for the planned development programs are anticipated to be funded out of current funds flow, existing lines of credit and funds from the exercising of employee unit options.

The Trust is continuing with its efforts to acquire producing and non producing properties through either property or corporate acquisitions.

The Trust has no contractual obligations that last more than one 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	$2,272,000	$248,000	$857,000	$619,000	$548,000

At December 31, 2005 the Trust had bank debt of $20,177,000 (2004 – $3,861,000). The Trust through its operating subsidiaries has bank revolving credit facilities totalling $36,900,000 at December 31, 2005 (December 31, 2004 - $32,000,000). The facilities carry an interest rate of Canadian chartered bank prime.

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 outstanding letters of credit of $340,000 at December 31, 2005. 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.

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

	2005		2004	
Issued	**Number**	**Amount**	**Number**	**Amount**
Trust Units				
Balance, beginning of year	14,943,405	$75,486,000	13,521,405	$ 51,763,000
Transfer of contributed surplus to Unit capital	–	169,000	–	159,000
Issued pursuant to public offering	–	–	1,100,000	21,450,000
Unit issue costs for public offering	–	–	–	(1,178,000)
Units issued on acquisition of Novitas	1,335,753	5,681,000	–	–
Unit issue costs on acquisition of Novitas	–	(259,000)		
Issued pursuant to Trust unit option plan	256,000	2,823,000	322,000	3,292,000
Balance, end of year	16,535,158	$83,900,000	14,943,405	$75,486,000

The Trust issued 1,335,753 units at a value of $25 per unit plus paid $769,000 in cash for all of the issued and outstanding common shares of Novitas. For accounting purposes the transaction was recorded at the cost of the Novitas' assets and liabilities due to Novitas being considered a related party to the Trust.

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,635,000 (2004 – 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.

A summary of the status of the Trust's unit option plan as of December 31, 2005 and 2004, and changes during the years ending on those dates is presented below:

	2005 Options	2005 Weighted-Average Exercise Price	2004 Options	2004 Weighted-Average Exercise Price
Outstanding at beginning of year	565,000	$ 11.56	937,000	$10.96
Options granted	407,000	23.32	10,000	15.60
Options exercised	(256,000)	11.03	(322,000)	10.22
Options cancelled	(70,000)	16.35	(60,000)	10.00
Outstanding at end of year	646,000	$ 18.67	565,000	$ 11.56
Options exercisable at end of year	214,000	$10.89	152,000	$ 11.52

The following table summarizes information about unit options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/05	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 12/31/05	Weighted-Average Exercise Price
$10.00	177,500	1.1 years	$10.00	177,500	$10.00
$15.20-$15.60	79,500	1.3 years	15.24	36,500	15.22
$22.45-$23.35	389,000	3.3 years	23.32	–	–
$10.00-$23.35	646,000	2.2 years	$18.67	214,000	$10.89

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 funds 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 18 percent on a BOE basis of its estimated 2006 production. The Trust uses a combination of fixed price swaps as well as no cost floor and collars to protect against commodity price declines.

Sensitivity Analysis

Sensitivity analysis, as estimated for 2006:

	Cash Flow	Cash Flow Per Unit
U.S. $1.00 per barrel	$ 1,037,000	$0.063
Canadian $0.10 per MCF	$ 238,000	$0.014
Change of Canadian $0.01/U.S. $ exchange rate	$ 644,000	$0.039

Additional Information

Additional information relating to the Trust may be found on SEDAR.COM as well as on the Trust's web sight 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, 2005 and 2004 and the consolidated statements of Unitholders' equity, operations and accumulated income, and 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, 2005 and 2004 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
Chartered Accountants

Calgary, Alberta
March 17, 2006

CONSOLIDATED BALANCE SHEETS

As at December 31	**2005**	2004
Assets		
Current		
Accounts receivable	**$ 11,020,000**	$ 7,104,000
Crude oil inventory	**836,000**	569,000
Parts inventory	**221,000**	391,000
Prepaid expenses	**781,000**	1,040,000
Investment in related party (Note 3)	**461,000**	461,000
	13,319,000	9,565,000
Abandonment deposit (Note 4)	**–**	1,522,000
Property and Equipment (Note 5)		
Petroleum and natural gas properties and related equipment	**139,798,000**	102,679,000
Accumulated depletion and depreciation	**(42,968,000)**	(28,777,000)
	96,830,000	73,902,000
	$ 110,149,000	$ 84,989,000
Liabilities		
Current		
Distribution payable	**$ 3,638,000**	$ 2,690,000
Accounts payable and accrued liabilities	**11,476,000**	11,962,000
Debt (Note 6)	**20,177,000**	3,861,000
	35,291,000	18,513,000
Future income tax liability (Note 7)	**4,341,000**	997,000
Asset retirement obligations (Note 8)	**13,195,000**	11,419,000
	52,827,000	30,929,000
Unitholders' Equity		
Unit capital (Note 9)	**83,900,000**	75,486,000
Contributed surplus	**636,000**	307,000
Accumulated earnings	**85,156,000**	51,688,000
Accumulated cash distributions	**(112,370,000)**	(73,421,000)
	57,322,000	54,060,000
	$ 110,149,000	$ 84,989,000

On behalf of the Board:

Director

Director

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

For the Years Ended December 31	2005	2004
Unitholders equity, beginning of year	**$ 54,060,000**	$ 36,983,000
Net earnings for the year	**33,468,000**	20,366,000
Net capital contributions (Note 9)	**2,823,000**	23,563,000
Units issued on acquisition of Novitas Energy Ltd. (Note 9)	**5,681,000**	–
Unit issue costs on acquisition of Novitas Energy Ltd. (Note 9)	**(259,000)**	–
Unit option adjustment for options expensed	**498,000**	236,000
Cash distributions	**(38,949,000)**	(27,088,000)
Unitholders' Equity, End of Year	**$ 57,322,000**	$ 54,060,000

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED INCOME

For the Years Ended December 31	2005	2004
Revenue		
Oil and gas sales	**$ 75,837,000**	$ 53,585,000
Royalties	**(8,995,000)**	(5,619,000)
Alberta royalty tax credit	**464,000**	305,000
Gain on sale of property (Note 5)	**263,000**	–
Interest and other	**33,000**	113,000
	67,602,000	48,384,000
Expenses		
Production costs	**20,203,000**	16,438,000
General and administrative	**2,420,000**	1,287,000
Interest on debt	**575,000**	493,000
Unit based compensation	**498,000**	236,000
Dry hole costs	**628,000**	480,000
Depletion, depreciation and accretion	**9,730,000**	7,912,000
	34,054,000	26,846,000
Earnings Before Income Taxes	**33,548,000**	21,538,000
Income taxes (recovery) (Note 7)		
Current	**(175,000)**	560,000
Future	**255,000**	612,000
	80,000	1,172,000
Net Earnings for the Year	**33,468,000**	20,366,000
Accumulated earnings at beginning of year	**51,688,000**	31,322,000
Accumulated Earnings at End of Year	**$ 85,156,000**	$ 51,688,000
Net Earnings Per Unit - Basic (Note 1)	**$ 2.04**	$ 1.43
Net Earnings Per Unit - Diluted (Note 1)	**$ 2.01**	$ 1.40

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31	**2005**	2004
Operating Activities		
Net earnings for the year	**$ 33,468,000**	$ 20,366,000
Items not affecting cash		
Gain on sale of property (Note 5)	**(263,000)**	–
Unit based compensation	**498,000**	236,000
Dry hole costs	**628,000**	480,000
Depletion, depreciation and accretion	**9,730,000**	7,912,000
Future income taxes	**255,000**	612,000
	44,316,000	29,606,000
Change in non-cash working capital		
Accounts receivable	**(2,814,000)**	(1,750,000)
Crude oil inventory	**(134,000)**	80,000
Parts inventory	**170,000**	(31,000)
Prepaid expenses	**306,000**	(324,000)
Accounts payable and accrued liabilities	**(2,584,000)**	2,236,000
Asset retirement obligations settled (Note 8)	**(275,000)**	(348,000)
	(5,331,000)	(137,000)
	38,985,000	29,469,000
Financing Activities		
Increase (decrease) in debt	**11,717,000**	(17,969,000)
Proceeds on issuance of units pursuant to public offering	**–**	21,450,000
Unit issue costs	**–**	(1,178,000)
Unit option proceeds	**2,823,000**	3,292,000
Unit issue costs on acquisition of Novitas Energy Ltd.	**(259,000)**	–
Unit distributions	**(38,001,000)**	(26,021,000)
	(23,720,000)	(20,426,000)
Investing Activities		
Property and equipment expenditures	**(16,669,000)**	(10,595,000)
Proceeds on sale of property (Note 5)	**1,097,000**	–
Abandonment deposit (Note 4)	**1,522,000**	(1,522,000)
Cash portion of Novitas Energy Ltd. acquisition (Note 2)	**(769,000)**	–
	(14,819,000)	(12,117,000)
Change in non-cash working capital		
Accounts receivable	**(534,000)**	(849,000)
Accounts payable and accrued liabilities	**88,000**	3,923,000
	(446,000)	3,074,000
	(15,540,000)	(9,391,000)
Net cash inflow	**–**	–
Cash, beginning of year	**–**	–
Cash, End of Year	**$ –**	$ –
Cash Interest Paid	**$ 575,000**	$ 493,000
Cash Taxes Paid	**$ 894,000**	$ 17,000

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the Years Ended December 31, 2005 and 2004

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. (Bonterra), Comstate Resources Ltd. (Comstate) and effective January 7, 2005, Novitas Energy Ltd. (Novitas)

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 for assets and liabilities 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 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

The Trust has a unit-based compensation plan, which is described in Note 9. The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. These amounts are recorded as contributed surplus. Any consideration paid by employees, directors or consultants on the exercise of these options is recorded as unit capital together with the related contributed surplus associated with the exercised options.

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 derivative financial instruments all match the production being hedged.

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, 2005 the Trust recorded a reduction to net revenue of $4,054,000 (2004 - $2,526,000).

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, 2005 of 16,594,260 (2004 – 14,557,489) included the weighted average number of units outstanding of 16,388,621 (2004 – 14,217,550) plus 205,639 (2004 – 339,939) units related to the dilutive effect of unit options.

2. ACQUISITION OF NOVITAS

On January 7, 2005 the Trust acquired Novitas. The acquisition was accounted for at Novitas' carrying value due to the related status of Novitas to the Trust. The carried values where as follows:

Accounts receivable	$ 568,000
Crude oil inventory	122,000
Prepaid expenses	47,000
Property and equipment	23,130,000
Accumulated depletion and depreciation	(6,522,000)
Accounts payable and accrued liabilities	(2,010,000)
Debt	(4,598,000)
Future income tax liability	(3,089,000)
Asset retirement obligations	(1,198,000)
	$ 6,450,000

The acquisition cost was $769,000 cash and the issuance of 1,335,753 trust units.

3. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 (December 31, 2004 – 689,682) common shares in Comaplex Minerals Corp (Comaplex), a company with common directors and management. The investment is recorded at cost. The fair market value as determined by using the trading price of the stock at December 31, 2005 was $2,448,000 (December 31, 2004 - $2,414,000). 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

As required by Province of Alberta Regulations the Trust provided a cash deposit with the Alberta Energy and Utilities Board for the future abandonment of specific wells. The deposit was refundable based on several conditions including abandonment or reactivation of inactive wells as well as meeting certain financial conditions. During the year the Trust was refunded the entire deposit. The deposit bore interest at Canadian chartered bank prime less approximately 2 percent.

5. PROPERTY AND EQUIPMENT

	2005		2004	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Undeveloped land	$ 334,000	$ -	$ 308,000	$ -
Petroleum and natural gas properites				
and related equipment	138,713,000	42,622,000	101,661,000	28,523,000
Furniture, equipment and other	751,000	346,000	710,000	254,000
	$139,798,000	$ 42,968,000	102,679,000	$ 28,777,000

On April 8, 2005, a former subsidiary of Novitas, Pine Cliff Energy Ltd.'s (Pine Cliff) (with common directors and management with the Trust) rights offering closed with over 97 percent of former Novitas shareholders exercising their rights to acquire common shares in Pine Cliff for $0.15 per common share. As part of the rights offering, the Trust agreed to sell to Pine Cliff effective January 1, 2005 (closing April 8, 2005) approximately 18 barrels per day of oil equivalent of production and some exploration lands formally held by Novitas for proceeds of approximately $1,000,000. As a result of this sale the Trust reported a gain on sale of property of $225,000. The Trust also disposed of minor non-core area properties for proceeds of $97,000 for a gain of $38,000.

6. DEBT

The Trust has a bank revolving credit facility of $36,900,000 at December 31, 2005 (2004 - $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 outstanding letters of credit. Letters of credit totalling $340,000 were issued at December 31, 2005. 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. 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, 2005 for this loan was $575,000 (2004 - $455,000).

7. INCOME TAXES

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

	2005	2004
Temporary differences related to assets and liabilities		
of the subsidiary companies	$ 5,919,000	$ 1,636,000
Finance costs in corporate subsidiaries	(12,000)	(33,000)
Corporate tax losses carried forward in the subsidiary companies	(1,566,000)	(606,000)
	$ 4,341,000	$ 997,000

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

	2005	2004
Earnings before income taxes	$ 33,548,000	$ 21,538,000
Combined federal and provincial income tax rates	38.08%	39.00%
Income tax provision calculated using statutory tax rates	12,775,000	8,400,000
Increase (decrease) in income taxes resulting from:		
Saskatchewan resource surcharge	347,000	–
Unit based compensation	190,000	92,000
Non-deductible crown royalties	1,793,000	1,317,000
Resource allowance	(3,283,000)	(2,399,000)
Trust income allocated to Unitholders	(12,763,000)	(6,181,000)
Adjustment on acquisition of Novitas	1,055,000	–
Others	(34,000)	(57,000)
	$ 80,000	$ 1,172,000

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	$ 8,199,000
Canadian oil and gas property expenditures	10	1,382,000
Canadian development expenditures	30	13,981,000
Canadian exploration expenditures	100	93,000
Income tax losses carried forward [1]	100	4,497,000
Finance costs	20	34,000
		$ 28,186,000

(1) Income tax losses carried forward expire in 2014 ($635,000) and 2015 ($3,862,000).

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

	Rate of Utilization %	Amount
Canadian oil and gas property expenditures	10	$ 17,886,000
Finance costs	20	913,000
Eligible capital expenditures	7	180,000
		$ 18,979,000

8. ASSET RETIREMENT OBLIGATIONS

At December 31, 2005, the estimated total undiscounted amount required to settle the asset retirement obligations was $39,921,000 (2004 - $28,360,000). Costs for asset retirement have been calculated assuming a 2.5 percent inflation rate for 2006 to 2010 and 1.5 percent thereafter. 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 (2004 – 5) percent.

Changes to asset retirement obligations were as follows:

	2005	2004
Asset retirement obligations, January 1	$ 11,419,000	$ 11,214,000
Adjustment to asset retirement obligation	234,000	(7,000)
Acquisition of Novitas	1,197,000	–
Liabilities settled during the year	(275,000)	(348,000)
Accretion	620,000	560,000
Asset retirement obligations, December 31	$ 13,195,000	$ 11,419,000

9. UNIT CAPITAL

Authorized

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

	2005		2004	
Issued	Number	Amount	Number	Amount
Trust Units				
Balance, beginning of year	14,943,405	$75,486,000	13,521,405	$ 51,763,000
Transfer of contributed surplus to Unit capital	–	169,000	–	159,000
Issued pursuant to public offering	–	–	1,100,000	21,450,000
Unit issue costs for public offering	–	–	–	(1,178,000)
Units issued on acquisition of Novitas	1,335,753	5,681,000	–	–
Unit issue costs on acquisition of Novitas	–	(259,000)		
Issued pursuant to Trust unit option plan	256,000	2,823,000	322,000	3,292,000
Balance, end of year	16,535,158	$83,900,000	14,943,405	$75,486,000

The Trust acquired Novitas on January 7, 2005. See Note 2 for details.

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,635,000 (2004 – 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.

A summary of the status of the Trust's unit option plan as of December 31, 2005 and 2004, and changes during the years is presented below:

	2005		2004	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	565,000	$ 11.56	937,000	$10.96
Options granted	407,000	23.32	10,000	15.60
Options exercised	(256,000)	11.03	(322,000)	10.22
Options cancelled	(70,000)	16.35	(60,000)	10.00
Outstanding at end of year	646,000	$ 18.67	565,000	$ 11.56
Options exercisable at end of year	214,000	$10.89	152,000	$ 11.52

The following table summarizes information about unit options outstanding at December 31, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/05	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 12/31/05	Weighted-Average Exercise Price
$10.00	177,500	1.1 years	$10.00	177,500	$10.00
$15.20-$15.60	79,500	1.3 years	15.24	36,500	15.22
$22.45-$23.35	389,000	3.3 years	23.32	–	–
$10.00-$23.35	646,000	2.2 years	$18.67	214,000	$10.89

The Trust records 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 3.5 (2004 – 2.87) percent, expected weighted average volatility of 31 (2004 – 30) percent, expected weighted average life of 2.5 (2004 – 3) years and an annual dividend rate based on the distributions paid to the Unitholders during the year.

10. RELATED PARTY TRANSACTIONS

The Trust received a management fee from Comaplex of $240,000 (2004 - $240,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses. The above fee represents the fair value of the services rendered.

As at December 31, 2005 the Trust had accounts receivable from Comaplex of $29,000 (December 31, 2004 - $45,000).

The Trust received a management fee from Pine Cliff of $132,000 for management services and office administration. This fee has been included as a recovery in general and administrative expenses. The above fee represents the fair value of the services rendered.

As at December 31, 2005 the Trust had an accounts receivable from Pine Cliff of $165. As at December 31, 2005 the Trust had an accounts payable of $16,000 to Pine Cliff in relation to outstanding post closing adjustment items for the sale of properties to Pine Cliff (see note 5).

11. 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 value of these financial instruments approximate their carrying value due to the short-term maturity of those instruments. 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.

12. COMMITMENTS, CONTINGENCIES AND GUARANTEES

The Trust entered into the following commodity hedging transactions in 2005 for a portion of its 2006 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, 2006 to June 30, 2006	Crude Oil	500 barrels	WTI	$65.07 per barrel
July 1, 2006 to September 30, 2006	Crude Oil	500 barrels	WTI	Floor of $65.00 and ceiling of $77.52 per barrel
May 1, 2005 to March 31, 2006	Natural Gas	2,000 GJ's	AECO	Floor of $6.75 per GJ (May 1, 2005 to October 31, 2005) and ceiling of $12.25 per GJ (November 1, 2005 to March 31, 2006)
November 1, 2005 to March 31, 2006	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $9.45 per GJ
April 1, 2006 to October 31, 2006	Natural Gas	2,000 GJ's	AECO	Floor of $8.55 and Ceiling of $14.00 per GJ

As at December 31, 2005 the fair value of the outstanding commodity hedging contracts was a net liability of $1,349,000.

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	$2,272,000	$248,000	$857,000	$619,000	$548,000

13. SUBSEQUENT EVENT- COMMITMENTS

The Trust entered into the following commodity hedging transactions subsequent to December 31, 2005 for a portion of its future production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
October 1, 2006 to December 31, 2006	Crude Oil	500 barrels	WTI	Floor of $70.00 per barrel and ceiling of $80.10 per barrel

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

Borden Ladner Gervais LLP, 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

Head Office

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