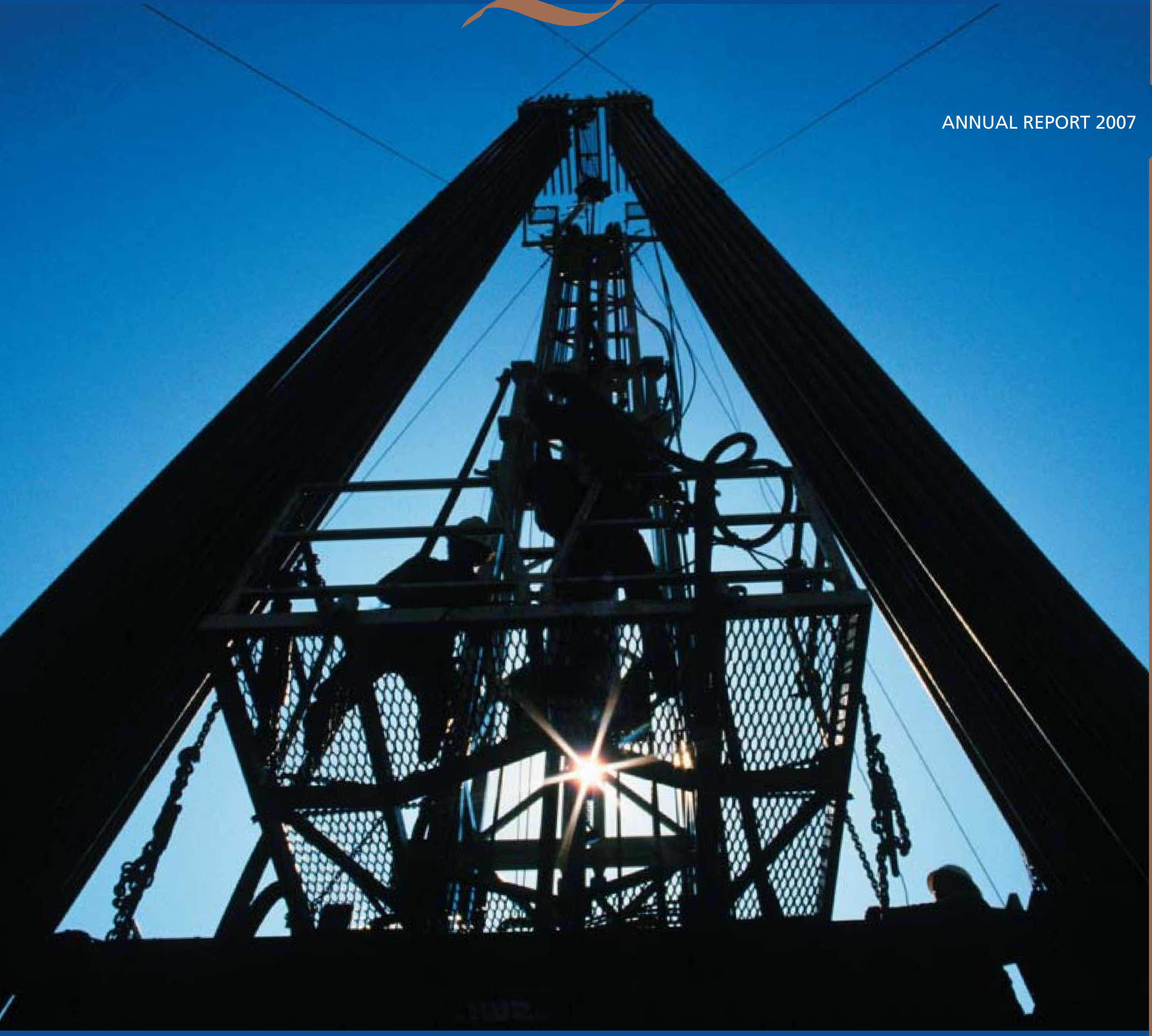
Bonterra
Energy Income Trust

ANNUAL REPORT 2007



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 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.

Contents

Notice of Annual General Meeting

The Annual General Meeting of Unitholders will be held on Thursday, May 22, 2008, in the Eau Claire Room at the Westin Hotel, 320 Fourth Avenue S.W., Calgary, Alberta, at 11:00 a.m. (Calgary time).

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 there from. 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.

Annual Highlights

	2007	2006	2005
Financial ($000, except $ per unit)			
Revenue – realized oil and gas sales	**96,431**	88,734	75,837
Distributions per Unit	**2.64**	2.82	2.37
Adjusted Distribution Base (1)	**53,815**	52,797	44,579
Per Unit Basic	**3.18**	3.15	2.72
Per Unit Fully Diluted	**3.18**	3.12	2.69
Payout Ratio	**83%**	90%	87%
Net Earnings	**30,350**	37,250	33,468
Per Unit Basic	**1.79**	2.23	2.04
Per Unit Fully Diluted	**1.79**	2.21	2.01
Capital Expenditures and Acquisitions (2)	**19,300**	38,348	56,703
Working Capital Deficiency	**58,766**	50,187	21,972
Unitholders' Equity	**44,218**	53,359	57,322
Units Outstanding (000's)	**16,928**	16,875	16,535
Operations			
Oil and Liquids (barrels per day)	**3,113**	3,040	2,713
Average Price ($ per barrel)	**70.31**	64.69	58.30
Natural Gas (MCF per day)	**6,627**	6,014	5,650
Average Price ($ per MCF)	**6.75**	7.55	8.64
Total BOE per day (3)	**4,218**	4,042	3,655
Reserves			
Oil and Liquids (barrels in 000's)			
Proved Developed Producing (Gross) (4)	**14,468**	13,688	13,840
Proved (Gross)	**17,472**	16,758	15,662
Proved plus Probable (Gross)	**21,910**	21,526	19,606
Natural Gas (MCF in 000's)			
Proved Developed Producing (Gross)	**19,863**	17,011	17,518
Proved (Gross)	**24,125**	22,562	20,473
Proved plus Probable (Gross)	**32,465**	29,700	25,582
Reserve Life Index (Oil, liquids and natural gas @ 6:1) (5)			
Proved Developed Producing	**11.3**	11.0	12.1
Proved	**13.7**	13.6	13.8
Proved plus Probable	**17.4**	17.6	17.3
Reserves in BOE's per Weighted Average Outstanding Unit			
Proved Developed Producing	**1.05**	0.98	1.02
Proved	**1.27**	1.22	1.16
Proved plus Probable	**1.62**	1.57	1.46

(See next page for footnote descriptions)

Quarterly Highlights

2007	4th	3rd	2nd	1st
Financial ($000, except $ per unit)				
Revenue – realized oil and gas sales	26,573	23,794	23,462	22,602
Adjusted Distribution Base (1)	15,842	13,149	11,695	13,129
Per Unit Basic	0.94	0.78	0.69	0.78
Per Unit Fully Diluted	0.94	0.77	0.69	0.78
Net Earnings	7,920	9,086	4,440	8,904
Per Unit Basic	0.47	0.54	0.26	0.53
Per Unit Fully Diluted	0.47	0.53	0.26	0.53
Cash Distributions	0.66	0.66	0.66	0.66
Capital Expenditures and Acquisitions	7,213	2,763	1,699	7,625
Total Assets	143,239	138,140	139,432	140,926
Working Capital Deficiency	58,766	50,041	49,595	49,288
Unitholders' Equity	44,218	50,820	51,920	57,646
Operations				
Oil and Liquids (barrels per day)	3,098	3,054	3,074	3,227
Natural Gas (MCF per day)	7,176	6,196	6,663	6,470
Total BOE per day (3)	4,295	4,086	4,184	4,305

(1) Adjusted distribution base (formally funds flow from operations) is not a recognized measure under GAAP. Management believes that in addition to net earnings, adjusted distribution base 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 adjusted distribution base as funds provided by operations before changes in non-cash operating working capital items excluding gain on sale of property and asset retirement expenditures.

The Canadian Institute of Chartered Accountants (“CICA”) recently published recommendations regarding disclosure of a measure called Standardized Distributable Cash. Please refer to page 24 of this report for the reconciliation between adjusted distribution base and standardized distributable cash.

(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 4,295 (2006 – 4,119, 2005 – 3,780).

Report to Unitholders

Bonterra Energy Income Trust ("Bonterra" or "the Trust") is pleased to report its operational and financial results for the year. The Trust generally, amongst other things, focused on:

- Development drilling from its large inventory of drill locations.
- Increasing production overall and on a per unit basis.
- The reduction of drilling and operating costs and to reduce the length of time between the day drilling is completed and the day the well commences production.
- Commencing with a study to determine the impact the new Alberta royalty structure will have on the inventory of drill locations and on the royalty rate on existing and new production. The Alberta government has not yet provided sufficient detail about the structure to determine the full impact. Bonterra has had direct discussions with the government and is working closely with the Canadian Association of Petroleum Producers and the Small Explorers and Producers Association of Canada to attempt to ensure that the government is aware of the negative impacts that some of its proposals will have on entities like Bonterra. The Trust is hopeful that the policy that will eventually be adopted by the Alberta government will be fair for the Province but will not have a major impact on entities like Bonterra's operations.
- Working with professional organizations to determine what the options are for Bonterra to lessen the impact of the Federal trust regulations that were legislated by the Federal government in June 2007.
- A property swap whereby it traded its Dodsland, Saskatchewan, properties for Pembina, Alberta, properties.

Bonterra is proud that in 2007 it has once again been successful in increasing on a per unit basis its commodity reserves, its adjusted distribution base (previously funds flow), and its production. Bonterra's ability to increase annual results on a per unit basis continues to be of prime importance. A continued above average return to the Trust's investors is the main objective.

Capital Spending and Production

In 2007 Bonterra's capital expenditure was $19,000,000, down from $38,000,000 in 2006. This reduction was caused mainly by not knowing what the impact of the Alberta royalty structure change will be and by the out of control drilling costs encountered in 2006. In 2007 the Trust drilled 22 gross (15.3 net) Cardium oil wells and 2 gross (0.7 net) Edmonton Sand natural gas wells with a 100 percent success rate.

The capital program was successful in replacing the 2007 annual production and in increasing overall reserves as well as increasing the daily production rate to 4,218 BOE from 4,042 in 2006. It is expected that average production will increase in 2008. The exit production rate for December 2007 was approximately 4,400 BOE per day.

The inventory of undrilled locations, net to the Trust, (subject to commodity prices and the terms of the new Alberta royalty structure) is:

Cardium oil and solution gas wells:	330
Natural gas wells	10
Total:	340

It is not anticipated that these drill locations will have any significant impact on production from existing wells.

Reserves

Gross proved plus probable crude oil and NGL reserves increased by 2 percent and gross proved plus probable natural gas reserves increased by 9 percent. These percentages were somewhat affected by the property swap whereby the Dodsland property ratio of oil to solution gas was higher than the ratio of oil to solution gas for the Pembina property. The reserve life index for 2007 (using Q4, 2007 production) is 17.4 years compared to 17.6 years in 2006. The slight reduction is due to Q4, 2007 production increasing to 4,295 BOE compared to 4,118 BOE in Q4, 2006. On a per unit basis the reserves in BOE per weighted average outstanding unit increased to 1.62 in 2007 from 1.57 in 2006.

The Trust is extremely pleased with its 2007 finding and development costs of $2.68 per BOE for proved plus probable reserve additions.

Bank Debt

Bank debt at December 31, 2007, was $57,422,000 compared to $45,379,000 in 2006. This represents a debt to funds flow ratio (by annualizing the Q4, 2007, adjusted distribution base) of 10.9 months compared to the 2006 ratio of 11 months. It is anticipated that this ratio will be reduced in 2008.

Cash Netback and Recycle Rate

Bonterra's cash netback in 2007 was $34.93 compared to $35.04 in 2006. It should be noted that due to an increase in production and commodity prices and the property swap, the Q4, 2007, netback increased to $40.09 compared to $34.96 for Q4, 2006. The Trust's recycle ratio in 2007 was 13.0 compared with 1.9 in 2006.

Return to Investors

The return to investors of 4.1 percent for 2007 from distributions less capital depreciation was substantially lower than normal and disappointing in comparison with the 20.3 percent return in 2006. It is always difficult to determine the causes. As previously outlined the Trust performed well from an operations perspective but three factors that are outside the control of Bonterra may have impacted the reduction in the unit price. The Federal government's legislation change to the taxation of Trusts, the announcement by the Alberta provincial government that the royalty rates will be increased, and tax loss selling are the three items that affected many oil and gas trusts and may also have had an impact on the price of Bonterra's units.

Despite the devaluation of the Trust unit price, the Trust's core business remains very strong and, subject to commodity prices, should remain strong for many years.

Outlook

Bonterra has decided to continue with a capital budget of $20,000,000 in 2008; the same as 2007. The major portion of this amount will come from the retention of 20 percent of the adjusted distribution base and the balance from the exercising of employee unit options. It is unlikely that any portion of this budget will require additional bank borrowing.

It is expected that the remaining 80 percent of the adjusted distribution base will be available for monthly distributions to unitholders.

General

The Board of Directors of the Trust's operating company and management wish to thank long time unitholders for their continued loyal support and advice and to welcome all new unitholders. A big thank you also goes to the staff for the large contribution that is made on a continuous basis towards the success of the Trust and for their positive approach and hard work.

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, 2007. 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 Shaunavon area 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, 2007 (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	13,624	12,909	19,863	15,281	844	627
Developed Non-Producing	9	9	907	731	1	1
Undeveloped	2,808	2,425	3,355	2,215	186	123
Total Proved	16,442	15,343	24,125	18,228	1,030	750
Probable	4,160	3,890	8,340	6,213	278	194
Total Proved Plus Probable	20,602	19,233	32,465	24,441	1,308	944

Reconciliation of Trust Gross Reserves by Principal Product Type (Forecast Prices and Costs)

	Light and Medium Oil and NGL's			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, 2006	16,758	4,768	21,526	22,562	7,138	29,700
Extension	719	180	899	1,350	(375)	975
Improved recovery	147	57	204	295	168	463
Technical revisions	1,473	(411)	1,062	1,066	1,363	2,429
Discoveries	–	–	–	–	–	–
Acquisitions	771	260	1,031	1,372	418	1,790
Dispositions	(1,288)	(357)	(1,645)	(448)	(185)	(633)
Economic factors	(27)	(59)	(86)	103	(187)	(84)
Production	(1,081)	–	(1,081)	(2,175)	–	(2,175)
December 31, 2007	17,472	4,438	21,910	24,125	8,340	32,465

Summary Of Net Present Values Of Future Net Revenue As Of December 31, 2007 (Forecast Prices And Costs)

	Net Present Value Of Future Net Revenue Before Income Taxes Discounted at (%/year)				
(M$) Reserve Category	0	5	10	15	20
Proved					
Developed Producing	834,718	489,936	351,815	279,759	235,358
Developed Non-Producing	4,009	3,167	2,570	2,131	1,799
Undeveloped	111,055	88,159	70,872	57,584	47,202
Total Proved	949,782	581,262	425,257	339,474	284,358
Probable	323,791	131,693	74,507	49,747	36,262
Total proved plus probable	1,273,573	712,955	499,764	389,222	320,620

Summary Of Net Present Values Of Future Net Revenue As Of December 31, 2007 (Forecast Prices And Costs)

	Net Present Value of Future Net Revenue After Income Taxes Discounted at (%/year)				
(M$) Reserve Category	**0**	**5**	**10**	**15**	**20**
Proved					
Developed Producing	687,026	422,853	313,885	255,463	260,016
Developed Non-Producing	3,375	2,690	2,204	1,846	1,573
Undeveloped	94,416	74,799	60,043	48,718	39,870
Total Proved	784,817	500,341	376,132	306,026	260,016
Probable	244,341	100,548	57,632	38,976	28,768
Total Proved Plus Probable	1,029,159	600,889	433,763	345,003	288,784

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)**
2008	88.17	6.19	52.29	65.72	90.30
2009	84.54	6.94	50.14	63.01	86.58
2010	83.16	7.46	49.32	61.98	85.17
2011	81.26	7.50	48.20	60.57	83.23
2012	80.73	7.41	47.88	60.17	82.68
2013	81.25	7.58	48.19	60.56	83.21
2014	82.88	7.76	49.16	61.78	84.88
2015	84.55	7.94	50.14	63.02	86.59
2016	86.25	8.12	51.15	64.28	88.33
2017	87.98	8.31	52.18	65.58	90.10

Crude oil, natural gas and liquid prices escalate at 2% per year thereafter.

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

1. 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.

2. 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.

3. 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:

	2007		2006	
	Oil and NGL (Bbls/day)	**Natural Gas (MCF/day)**	**Oil and NGL (Bbls/day)**	**Natural Gas (MCF/day)**
Pembina, Alberta	2,346	5,555	2,178	4,768
Shaunavon, Saskatchewan	310	–	348	–
Dodsland, Saskatchewan [1]	206	97	251	141
Peck Lake, Saskatchewan	–	293	–	392
Pinto, Saskatchewan	65	80	72	97
Redwater, Alberta	37	79	36	73
Midale, Saskatchewan	39	4	40	8
Other	110	519	115	535
	3,113	6,627	3,040	6,014

(1) Disposed of on October 30, 2007

Land Holdings

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

	2007		2006	
	Gross Acres	**Net Acres**	**Gross Acres**	**Net Acres**
Alberta	133,216	83,609	119,777	73,431
Saskatchewan	33,778	30,409	63,136	48,538
	166,994	114,018	182,913	121,969

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:

	2007	**2006**
Acquisitions (1)	$ 18,369,000	$ –
Disposals (1)	(17,664,000)	–
Exploration and development costs	18,595,000	38,348,000
Net petroleum and natural gas capital expenditures	$ 19,300,000	$ 38,348,000

(1) Included in acquisitions and disposals is an asset swap valued at $17,664,000.

Drilling History

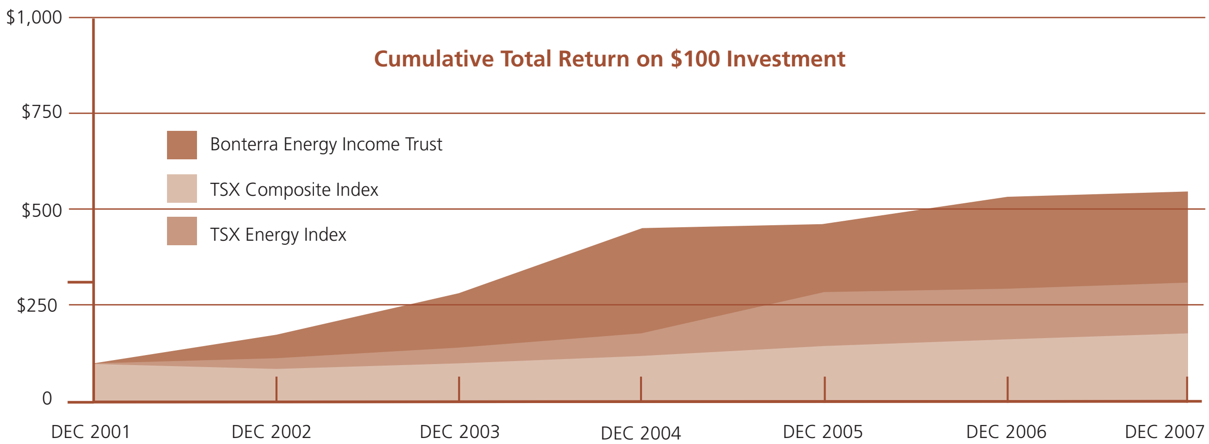
The following table summarizes the Trust's gross and net drilling activity and success:

	2007					
	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude Oil	22	15.3	–	–	22	15.3
Natural Gas	2	0.7	–	–	2	0.7
Dry	–	–	–	–	–	–
Total	24	16.0	–	–	24	16.0
Success rate	100%	100%	–	–	100%	100%

	2006					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	43	30.3	–	–	43	30.3
Natural Gas	9	6.5	–	–	9	6.5
Dry	9	8.8	–	–	9	8.8
Total	61	45.6	–	–	61	45.6
Success rate	85%	81%	–	–	85%	81%

	2005					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude Oil	42	15.0	–	–	42	15.0
Natural Gas	2	1.0	–	–	2	1.0
Dry	4	2.5	–	–	4	2.5
Total	48	18.5	–	–	48	18.5
Success rate	92%	86%	–	–	92%	86%

Market Performance



December	2001	2002	2003	2004	2005	2006	2007
Bonterra Energy Income Trust (Notes 1)	$100	$175	$284	$452	$464	$534	**$550**
Tsx Composite Index	$100	$86	$107	$121	$147	$168	**$180**
Tsx Energy Index	$100	$113	$139	$179	$286	$290	**$313**

Trust Unit Trading Statistics

Unit Prices (based on daily closing price)	2007	2006
High	**$30.80**	$37.85
Low	**$22.19**	$23.60
Close	**$23.99**	$25.57
Daily Average Trading Volume	**17,867**	31,417

Property Discussions

Bonterra has an excellent asset base consisting of concentrated, stable and under-developed properties with large amounts of remaining oil in place, a long reserve life, with low risk and predictable reserves. Management feels that it's stable asset base with its predictable production profile represents the most suitable reserve base for a trust. The high wellhead prices received and the low royalty rates paid equates to Bonterra having among the highest netbacks in the industry. Management has continually proven it can manage these high quality assets to generate long-term value.

The Trust's major producing properties are located in the Pembina area of Alberta, the Shaunavon area in southwest Saskatchewan, and the southeast area of Saskatchewan. Bonterra's reserves and production growth will come from exploiting it's high remaining oil in place properties primarily from it's large inventory of low risk internally generated exploitation and drilling programs that have predictable results. The Trust will continue to maintain its financial flexibility so it can 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 89.9% of the Trust's total reserves. The high concentration of interest in a single area allows for better focused management of it's assets including an improved ability to manage cost and efficiently invest capital. This production is predominately predictable, long life, low decline, and high quality light oil and associated liquid rich solution gas from the Cardium formation that is located at an average depth of approximately 1,550 meters.

Bonterra operates approximately 83 percent of its Pembina production which allows for significant operating efficiencies. The property contains approximately 456 gross (394 net) operated producing wells with an 86 percent average working interest and 167 gross (29 net) non-operated producing wells with an approximate 17 percent average working interest.

This large land holding, large amount of remaining oil in place 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 and maximize income in the area through drilling, through low-cost optimization opportunities, and 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 improved recovery.

On October 30, 2007, (with an effective date of May 1, 2007), Bonterra swapped it's interest in the Dodsland Area of Saskatchewan for producing properties in the Pembina Area. This swap further consolidated Bonterra's land position in the area, increasing operated volumes in the area by approximately 256 BOE/d. The Trust also realized significant benefits in operating cost reductions and added additional drilling opportunities as a result of the transaction.

The Trust's large drilling inventory has enabled it to increase production volumes. A Cardium infill drilling program was initiated on Bonterra's operated and non-operated properties in 2003 and has continued successfully through 2007 and will continue into 2008 and beyond. The continuation of the Cardium drilling program will allow the Trust to maintain and increase its production rates and reserves.

Bonterra has significant potential upside in the Pembina Cardium field with the implementation of a miscible CO_2 enhanced oil recovery scheme. There is significant uncertainty over the economic feasibility of enhanced oil recovery using CO_2 however an industry operator is currently running a miscible CO_2 flood pilot offsetting Bonterra lands. Details of the pilot are confidential; however, public information released by the operator is encouraging stating that a comprehensive EOR program could increase the ultimate recovery factor by approximately 15%. Increasing environmental concern over CO_2 emissions and the current high price environment are improving the viability of CO_2 flooding however a long term low cost source of CO_2 and supportive environmental regulations will be key to its implementation. The Trust has a large land base that may be suitable for CO_2 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 is currently evaluating Belly River re-completion potential in several suspended Cardium well bores.

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 continued to drill wells on its expanded shallow gas land base in 2007 and plans to continue shallow gas drilling in 2008. Bonterra is targeting low-cost optimization opportunities in existing producing wells, and anticipates further re-completions in the shallow gas zones, taking advantage of the new commingling regulations for gas wells. The Trust is also in the preliminary stages of assessing its shallow gas land base for the potential to increase well densities in order to maximize recoveries.

Bonterra has been assessing production of coal bed methane (CBM) in the Pembina area 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 CBM potential. Due to regulatory delays, uncertainty by regulators, lower gas prices, and high costs of services, Bonterra has delayed this project until all regulatory concerns are rectified and project economics improve. 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

On October 30, 2007 (with an effective date of May 1, 2007), Bonterra swapped its interest in the Dodsland Area for producing properties in the Pembina Area.

Shaunavon Area, Southwest Saskatchewan

Bonterra operates this major producing property which consists of approximately 50 producing wells in the Shaunavon area of southwest Saskatchewan where the Trust's working interest averages approximately 92 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. Bonterra continues to evaluate this area to determine if further optimization programs may increase overall profitability from the properties and it is expected that several identified low-cost optimization activities will commence in 2008.

The Trust is continuing to assess its undeveloped acreage to determine if there is potential exploration or development prospects in the area. The Trust has reached a farm-out agreement, with favorable terms, on one section of land in the Shaunavon Area. It is expected that drilling will commence in 2008.

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 its properties in the area.. 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.

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 18, 2008 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, 2007, together with the notes related thereto.

Forward-looking Information

Certain statements contained in this MD&A include statements which contain words such as "anticipate", "could", "should", "expect", "seek", "may", "intend", "likely", "will", "believe" and similar expressions, statements relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions. Forward-looking information in this MD&A includes, but is not limited to: expected cash provided by continuing operations; cash distributions; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas trusts to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; opportunities available to or pursued by us; and other factors, many of which are beyond our control. The foregoing factors are not exhaustive and are further discussed herein under the heading Business Prospects, Risks and Outlooks as well as in the Trust's Annual Information Form filed on SEDAR at www.sedar.com.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do so, what benefits will be derived therefrom. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

The forward-looking information contained herein is expressly qualified by this cautionary statement.

Annual Comparisons

Financial ($000, except $ per unit)	2007	2006	2005
Revenue – realized oil and gas sales	**96,431**	88,734	75,837
Adjusted Distribution Base (1)	**53,815**	52,797	44,579
Per Unit Basic	**3.18**	3.15	2.72
Per Unit Fully Diluted	**3.18**	3.12	2.69
Payout Ratio	**83%**	90%	87%
Net Earnings	**30,350**	37,250	33,468
Per Unit Basic	**1.79**	2.23	2.04
Per Unit Fully Diluted	**1.79**	2.21	2.01
Cash Distributions per Unit	**2.64**	2.82	2.37
Capital Expenditures and Acquisitions	**19,300**	38,348	56,703
Total Assets	**143,239**	134,942	110,149
Working Capital Deficiency	**58,766**	50,187	21,972
Unitholders' Equity	**44,218**	53,359	57,322
Operations			
Oil and Liquids *(barrels per day)*	**3,113**	3,040	2,713
Natural Gas *(MCF per day)*	**6,627**	6,014	5,650
Total BOE per day	**4,218**	4,042	3,655

Quarterly Comparisons

2007 Financial ($000, except $ per unit)	4th	3rd	2nd	1st
Revenue – realized oil and gas sales	26,573	23,794	23,462	22,602
Adjusted Distribution Base (1)	15,842	13,149	11,695	13,129
Per Unit Basic	0.94	0.78	0.69	0.78
Per Unit Fully Diluted	0.94	0.77	0.69	0.78
Payout Ratio	70%	85%	96%	85%
Net Earnings	7,920	9,086	4,440	8,904
Per Unit Basic	0.47	0.54	0.26	0.53
Per Unit Fully Diluted	0.47	0.53	0.26	0.53
Cash Distributions	0.66	0.66	0.66	0.66
Capital Expenditures and Acquisitions	7,213	2,763	1,699	7,625
Total Assets	143,239	138,140	139,432	140,926
Working Capital Deficiency	58,766	50,041	49,595	49,288
Unitholders' Equity	44,218	50,820	51,920	57,646
Operations				
Oil and Liquids *(barrels per day)*	3,098	3,054	3,074	3,227
Natural Gas *(MCF per day)*	7,176	6,196	6,663	6,470
Total BOE per day	4,295	4,086	4,184	4,305

2006 Financial ($000, except $ per unit)	**4th**	**3rd**	**2nd**	**1st**
Revenue – realized oil and gas sales	21,719	23,665	23,219	20,131
Adjusted Distribution Base (1)	12,235	14,401	14,008	12,153
Per Unit Basic	0.72	0.86	0.84	0.73
Per Unit Fully Diluted	0.72	0.85	0.83	0.72
Payout Ratio	100%	84%	82%	95%
Net Earnings	6,471	10,441	10,617	9,721
Per Unit Basic	0.39	0.62	0.64	0.58
Per Unit Fully Diluted	0.38	0.62	0.63	0.58
Cash Distributions	0.72	0.72	0.69	0.69
Capital Expenditures and Acquisitions	9,457	12,597	6,246	10,048
Total Assets	134,942	130,655	122,166	118,439
Working Capital Deficiency	50,187	38,853	28,820	25,532
Unitholders' Equity	53,359	60,387	61,202	61,365
Operations				
Oil and Liquids *(barrels per day)*	3,138	3,024	3,001	2,996
Natural Gas *(MCF per day)*	5,885	5,925	6,181	6,071
Total BOE per day	4,119	4,012	4,031	4,008

(1) Adjusted distribution base (formally funds flow from operations) is not a recognized measure under GAAP. Management believes that in addition to net earnings, adjusted distribution base 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 adjusted distribution base as funds provided by operations before changes in non-cash operating working capital items excluding gain on sale of property and asset retirement expenditures.

The Canadian Institute of Chartered Accountants ("CICA") recently published recommendations regarding disclosure of a measure called Standardized Distributable Cash. Please refer to page 24 of this report for the reconciliation between adjusted distribution base and standardized distributable cash.

Disclosure Controls and Procedures

Disclosure controls and procedures are defined under Multilateral Instrument 52-109 – Certification of Disclosure Controls in Issuers' Annual and Interim Filings ("MI 52-109") as ".. controls and other procedures of an issuer that are designed to provide reasonable assurance that information required to be disclosed by the issuer in its annual filings, interim filings or other reports filed or submitted by it under provincial and territorial securities legislation is recorded, processed, summarized and reported within the time periods specified in the provincial and territorial securities legislation and include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in its annual filings, interim filings or other reports filed or submitted under provincial and territorial securities legislation is accumulated and communicated to the issuer's management, including its chief executive officers and chief financial officers (or persons who perform similar functions to a chief executive officer or a chief financial officer), as appropriate to allow timely decisions regarding required disclosure." The Trust has conducted a review and evaluation of its disclosure controls and procedures, with the conclusion that as at December 31, 2007 the Trust has an effective system of disclosure controls and procedures as defined under MI 52-109. In reaching this conclusion, the Trust recognizes that two key factors must be and are present:

1. the Trust is very dependent upon its advisors and consultants (principally its legal counsels) to assist in recognizing, interpreting, understanding and complying with the various securities regulations disclosure requirements; and
2. an active Board and management with open lines of communications.

The Trust has a small staff with varying degrees of knowledge concerning the various regulatory disclosure requirements. In many circumstances, the various regulatory requirements are relatively new, subject to interpretation, and complex. The Trust is not of sufficient size to justify a separate department or one or more staff member specialists in this area. Therefore the Trust must rely upon its advisors/consultants to assist it and as such they form part of the disclosure controls and procedures.

Proper disclosure necessitates that a person not only be aware of the pertinent disclosure requirements, but must also be sufficiently involved in the affairs of the Trust and/or receives the communication of information to assess any necessary disclosure requirements. Accordingly, it is essential that there be proper communication among those people who manage and govern the affairs of the Trust, this being the Board of Directors and senior management. The Trust believes this communication exists.

While the Trust believes it has adequate disclosure controls and procedures in place, lapses in the disclosure controls and procedures could occur and/or mistakes could happen. Should such occur, the Trust intends to take whatever steps it deems necessary to minimize the consequences thereof.

Internal Controls Over Financial Reporting

Internal controls over financial reporting are defined in MI 52-109 as "... a process designed by, or under the supervision of, the issuer's chief executive officers and chief financial officers, or persons performing similar functions, and effected by the issuer's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the issuer's GAAP and includes those policies and procedures that:

1. pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the issuer;
2. provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the issuer's GAAP, and that receipts and expenditures of the issuer are being made only in accordance with authorizations of management and directors of the issuer; and
3. provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the issuer's assets that could have a material effect on the annual financial statements or interim financial statements."

The Trust has conducted a review and evaluation of its internal controls over financial reporting, with the conclusion that as of December 31, 2007 the Trust's system of internal controls over financial reporting as defined under MI 52-109 is adequately designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. In its evaluation, the Trust identified certain material weaknesses in internal controls over financial reporting:

1. due to the limited number of staff at the Trust, it is not feasible to achieve the complete segregation of incompatible duties; and
2. due to the limited number of staff, the Trust relies upon third parties as participants in the Trust's internal controls over financial reporting.

The Trust believes these weaknesses are mitigated by: the active involvement of senior management and the board of directors in the affairs of the Trust; open lines of communication within the Trust; the present levels of activities and transactions within the Trust being readily transparent; the thorough review of the Trust's financial statements by management, the board of directors and by the Trust's auditors (annual statements only); and the establishment of a whistle-blower policy. However, these mitigating factors will not necessarily prevent a material misstatement occurring as a result of the aforesaid weaknesses in the Trust's internal controls over financial reporting. A system of internal controls over financial reporting, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the internal controls over financial reporting are met.

Production

The Trust's 2007 average production of oil and natural gas liquids was 3,113 (2006 – 3,040) barrels per day and natural gas production in 2007 averaged 6,627 (2006 – 6,014) MCF per day. Oil production increased by approximately 2.5 percent while gas production increased by approximately 10 percent. The increased crude oil production was predominantly due to the Trusts 2006 and 2007 development programs. Natural gas increase was a combination of the 2006 development program and the asset swap concluded on October 30, 2007.

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 2007. Bonterra tied-in 3 gross and net Cardium oil wells and 2 gross and net natural gas wells in December. The Trust also completed an asset exchange resulting in the disposition of its interest in the Dodsland area of Saskatchewan for further property interests in the Pembina area of Alberta. The net result was a slight reduction in volumes on a BOE basis with Dodsland representing approximately 265 BOE's per day and the acquired properties producing approximately 250 BOE's. However the newly acquired properties had an average operating cost per BOE of $12.60 compared to $36.50 for the Dodsland assets offset slightly by larger royalties.

The Trust's overall annual decline rate for 2007 was approximately nine percent which the Trust was able to more than offset with its 2007 drill program. The Trust, along with its partners, drilled 22 gross (15.3 net) Cardium oil wells. This includes 15 gross and 14.3 net Cardium wells drilled directly by the Trust. Also the Trust drilled 2 gross (.7 net) shallow gas wells in 2007. The Trust experienced a 100 percent success rate with its 2007 drilling program.

As at December 31, 2007 Bonterra had 7 gross (6.3 net) Cardium oil wells, 2 gross (2 net) natural gas wells and 3 gross (2.5 net) coal-bed (CBM) wells with assigned reserves drilled but not on production. Subsequent to December 31, 2007 and up to the date of this report, Bonterra has put on production all of its Cardium oil wells and one shallow gas well. The timing for the tie-in of the remaining natural gas and CBM wells has not yet been determined.

Revenue

Gross revenue from petroleum and natural gas sales prior to royalties was $96,431,000 (2006 – $88,734,000). The increase of $7,697,000 was due to increased production volumes and an increase in the average price received for crude oil offset partially by a 10.6 percent decline in the average price of natural gas. The price received for crude oil increased to $70.31 per barrel in 2007 from $64.69 per barrel in 2006 while natural gas prices decreased to $6.75 per MCF in 2007 from $7.55 per MCF in 2006.

The fourth quarter saw a substantial increase in gross revenues of $2,779,000 over quarter three due to increased production and increased commodity prices. Production in the fourth quarter averaged 4,295 BOE's per day compared to 4,088 in the third quarter. Also the average price received in the fourth quarter for crude oil and natural gas liquids was $77.60 ($73.68 third quarter) per barrel and $6.70 ($5.47 third quarter) per MCF for natural gas.

Although the Trust received higher net commodity prices in 2007 than in 2006, 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 2007's cash flow from operations was approximately 26 cents per unit and approximately 24 cents per unit on net earnings.

Included in gross revenue is a realized gain on risk managemen contracts of $621,000 (2006 – ($62,000)) due to higher prices received as a result of price hedging. The Trust also reported an unrealized loss on risk management contracts of $3,085,000 due to the elimination of hedge accounting effective October 1, 2007. The Trust may 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. With the property swap of the Dodsland property the Trust has reduced its hedging percentage to approximately 25 percent of its anticipated forward production. The Trust will 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, 2008 to June 30, 2008	Crude Oil	1,000 barrels	WTI	Floor of $73.00 and ceiling of $83.00 per barrel
July 1, 2008 to December 31, 2008	Crude Oil	500 barrels	WTI	Floor of $73.00 and ceiling of $80.68 per barrel
November 1, 2007 to March 31, 2008	Natural Gas	2,000 GJ's	AECO	Floor of $6.50 and ceiling of $10.37 per GJ

Subsequent to December 31, 2007 and up to the date of this report the Trust has entered into the following commodity hedging transactions:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
July 1, 2008 to December 31, 2008	Crude Oil	500 barrels	WTI	Floor of $85.00 and ceiling of $104.80 per barrel
April 1, 2008 to October 31, 2008	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $7.60 per GJ

As at December 31, 2007 the fair value of the outstanding commodity hedging contracts was a net liability of $3,085,000 (December 31, 2006 – net asset $1,189,000).

Royalties

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During 2007 the Trust paid $9,209,000 (2006 – $8,156,000) in Crown royalties and $3,235,000 (2006 – $1,996,000) 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 ten percent (2006 – ten percent) and approximately three percent (2006 – two percent) for other royalties before hedging adjustments.

During 2007, the Trust was advised by the owner of a gross overriding royalty that the production limit, resulting in an additional gross overriding royalty in respect of certain of its Cardium oil wells, had been reached. The production limit was triggered by a calculation on a multitude of Cardium wells including many that were not owned by the Trust.

In addition the exact wells that the production limit was applicable to was not readily known by the Trust nor easily determined. In discussions with the payee it was determined that the production limit was reached in late 2005. The royalty has been calculated based on this agreed date and the affected wells for Bonterra and other operators in the area were identified. The approximate amount of the adjustment, net to the Trust is $570,000 for periods prior to January 1, 2007. The monthly amount of the royalty on a go forward basis is approximately $55,000 per month based on current pricing and production levels.

Also in 2007 the Trust was informed by the operator of its Dodsland property that it had not been charged a net profit royalty for the years 2004, 2005 and 2006. In review of the agreements it was confirmed no payment was made and an amount of approximately $150,000 was paid by the Trust for the net profit royalty.

Royalty rates in the fourth quarter averaged approximately 13 percent; slightly higher than preceding quarters (after the elimination of the above mentioned adjustments). The asset swap of the Dodsland properties for the Pembina properties resulted in an increase of approximately one percent in the average royalty rate for the Trust.

The Trust was eligible for Alberta Crown Royalty rebates for Alberta production from all wells that it drilled on Crown lands and from a small number of purchased wells; however this program was discontinued by the Alberta Government effective January 1, 2007 which resulted in a reduction of revenue of $500,000 in 2007.

Gain on Sale of Property

The Trust disposed of its interests in a non-core, non-operated property on January 1, 2006 for proceeds of $750,000 resulting in a gain on sale of $532,000. Production from this property averaged ten barrels per day in 2005.

Production Costs

Production costs totalled $24,073,000 in 2007 compared to $22,238,000 in 2006. On a barrel of oil equivalent (BOE) basis 2007 operating costs were $15.64 compared to $15.07 for 2006. 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. Operating costs on the Trust's newly acquired Pembina properties from the swap as well as on the newly drilled wells are significantly lower on a BOE basis than on its Dodsland property and the older low productivity wells and this may result in lower operating costs per BOE in the future.

Operating costs were $5,535,000 in the fourth quarter of 2007 compared to $6,401,000 in the third quarter. The decrease was due primarily to the above mentioned asset swap which resulted in approximately $375,000 less operating costs as well as an approximate $300,000 operating cost adjustment related to previously expensed surface lease payments that pertained to periods subsequent to the closing date of the asset swap.

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 continually examining means of reducing operating costs.

With the asset exchange, the Trust anticipates operating costs in the $13.50 to $14.50 per BOE range for 2008. The higher operating costs for the Trust are substantially offset by low royalty rates of approximately 13 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 $2,603,000 in 2007 compared to $2,295,000 in 2006. On a BOE basis, general and administrative expenses in 2007 averaged $1.69 compared to $1.56 per BOE in 2006. The Trust is managed internally. In addition, the Trust provides administrative services to Comaplex Minerals Corp. (Comaplex) and Pine Cliff Energy Ltd. (Pine Cliff), companies that share common directors and management. Please refer to discussion under Related Party Transactions for details.

The Trust's only significant general and administrative costs are employee compensation and professional services such as legal, engineering and audit. Employee compensation expense increased by approximately 8.5 percent ($252,000). This increase has been partially offset by increased overhead recoveries charged to operations and capital programs. Costs associated with professional services increased by approximately $450,000. Of this increase approximately $340,000 related to the evaluation of several organizational options. This review was part of the Trusts continuing examination of means to address the changes resulting from the federal government's taxation of Trust's announcement on October 31, 2006 and enacted into law in 2007. The balance of the increase pertained to increased costs associated with producing the Trust's engineering report as well as fees related to the audit and continuous disclosure requirements.

The fourth quarter general and administrative expenses were $34,000 lower than the third quarter. The decrease was primarily due to the Trust incurring costs of $275,000 for professional fees in the third quarter for services discussed above offset partially by an increase in the fourth quarter bonus amount and increased cost adjustments related to engineering and audit services.

Interest Expense

Interest expense for the 2007 fiscal year of the Trust was $3,028,000 (2006 – $1,610,000). The increase was due to increased loan balances resulting from the Trust's 2006 and 2007 capital programs. Interest rates during the year on the outstanding debt averaged approximately 5.9 (2006 – 5.3) percent. The Trust maintained an average outstanding debt balance of approximately $51,600,000 (2006 – $31,000,000). Total debt (including negative working capital) as of December 31, 2007 represents approximately 13.1 months of 2007 annual adjusted distribution base or 11.1 months based on annualized 2007 fourth quarter adjusted distribution base. The ratio of bank debt only as of December 31, 2007 based on the annualized 2007 Q4 base was 10.9 months.

The Trust believes that maintaining debt at or less than one year's adjusted distribution base (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 CBM potential without requiring the issuance of trust units. The Trust's December 31, 2007 debt level including working capital is slightly below this level.

The Trust's current bank agreements for the Trust's wholly owned operating subsidiaries (each of Bonterra Energy Corp (Bonterra Corp.), and Novitas Energy Ltd. (Novitas) have their own) provide for a combined $69,900,000 (December 31, 2006 – $49,900,000) of available credit facility. Bank debt at December 31, 2007 was $57,422,000 (December 31, 2006 – $45,379,000). 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 half percent lower than that charged on the general loan account.

Unit Option Based Compensation

Unit option based compensation is a statistically calculated value representing the estimated expense of issuing employee unit options. The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants.

In 2007, the Trust issued 553,000 unit options of which 517,000 were issued at the end of June 2007 at an average price of $28.31 and a fair value of $2.75 per unit. The fair value of the options granted has been estimated using the Black-Scholes option pricing model, assuming a weighted risk free interest rate of 4.7 (2006 – 4.1) percent, expected weighted average volatility of 27 percent (2006 – 27), expected weighted average life of 2.3 years (2006 – 2.5) and an annual dividend rate based on the distributions paid to the Unitholders during the year. The future unit based compensation impact of these options is approximately $250,000 per quarter over the next four quarters.

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.

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, 2007, the estimated total undiscounted amount required to settle the asset retirement obligations was $54,622,000 (2006 – $46,434,000). Of the $8,188,000 increase, approximately $2.7 million is due to the asset swap (the Dodsland property had no asset retirement obligation associated with it as the Trust had the option of transferring back the title to the wells to a third party who would then inherit this obligation).

These obligations will be settled based on the useful lives of the underlying assets, which extend up to 50 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 $2,504,000. While a one percent decrease in the risk adjusted rate would increase the asset retirement obligation by $3,430,000.

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 is used to calculate depletion. 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, 2007, the Trust expensed $16,675,000 (2006 – $15,393,000) for the above-described items including $3,078,000 (2006 – $2,919,000) for dry hole costs. During 2007 the Trust wrote off all costs related to 8 wells drilled during the period 2004-2006 since the independent third party engineers did not attribute any reserves to them as well as some 2007 carryover costs related to wells written off in 2006. As of December 31, 2007 all capitalized costs have been assigned reserves and in the future any facilities that do not have reserves attributed to them will be written off.

The Trust has experienced a significant reduction in finding and development costs during the current year (see discussion under Finding and Development Costs) resulting in a marginal decrease in costs per barrel of reserves. Based on year end reserves, the Trusts average cost of proved reserves is $5.84 (2006 – $5.95) per BOE.

The Trust currently has an estimated reserve life for its proved developed producing reserves of 11.3 (2006 – 11) years calculated using the Trust's gross reserves (prior to allowance for royalties) based on the third party engineering report dated December 31, 2007 and using fourth quarter 2007 average production rates of 4,295 BOE's (2006 – 4,119 BOE's). Based on total proved reserves the Trust has a 13.7 (2006 – 13.6) year reserve life and if proved and probable are used the reserve life increases to 17.4 (2006 – 17.6) years. These figures are some of the longest (excluding oil sands) reserve life indexes in the Trust sector.

Taxes

On October 31, 2006, the Canadian Federal Government announced a proposed Trust taxation pertaining to taxation of distributions paid by publicly traded income trusts and this was enacted by legislation in June 2007. Previously, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and the tax is paid on the distributions by the unitholders. The June 2007 legislation results in a two-tiered tax structure whereby distributions commencing in 2011 would first be subject to a 28 (previously 31.5) percent tax at the Trust level and then investors would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation.

Future income tax expense for 2007 increased by a one time adjustment of $4,076,000, with a corresponding increase to the future tax liability as a result of the June 2007 enactment. Until June 2007, the Trust had been tax effecting the reversal of taxable temporary differences at a nil tax rate on the assumption that the Trust would make sufficient tax deductible cash distributions to unitholders such that the Trust's taxable income would be nil for the foreseeable future and the tax burden would have continued to be with whomever received the monthly distribution. The new legislation limits the tax deductibility of cash distributions such that income taxes may become payable in the future.

The Trust has estimated its future income taxes based on its best estimates of results from operations and tax pool claims and cash distributions in the future assuming no material change to the Trust's current organizational structure. As currently interpreted, Canadian Generally Accepted Accounting Principles ("GAAP") does not permit the Trust's estimate of future income taxes to incorporate any assumptions related to a change in organizational structure until such structures are given legal effect even though it is anticipated that many trusts will change their organizational structure to attempt to reduce this impact.

The Trust's estimate of its future income taxes will vary as to the Trust's assumptions pertaining to the factors described above, and such variations may be material.

Until 2011, the new legislation does not directly affect the Trust's cash flow from operations, and accordingly, the Trust's financial condition.

Currently 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.") and Novitas Energy Ltd. ("Novitas") and these corporations may periodically be taxable. These corporations pay the majority of their income to the Trust through interest and royalty payments which are deductible for income tax purposes. The current tax provision relates to resource surcharge payable by the Trusts subsidiaries to the Province of Saskatchewan. The surcharge is calculated as a flat percent of revenues generated from the sale of petroleum products produced in Saskatchewan. The provincial government of Saskatchewan has reduced the current resource surcharge rate of 3.3 percent to 3.1 percent on July 1, 2007 and to 3.0 percent on July 1, 2008.

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	$16,921,000
Canadian oil and gas property expenditures (COGPE)	10	1,771,000
Canadian development expenditures (CDE)	30	30,431,000
Canadian exploration expenditures (CEE)	100	93,000
Income tax losses carried forward (1)	100	15,056,000
		$64,272,000

(1) Income tax losses carried forward expire in 2014 ($635,000), 2015 ($3,574,000), 2026 ($4,826,000) and 2027 ($6,021,000).

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

	Rate of Utilization %	**Amount**
COGPE	10	$14,409,000
Finance costs	20	339,000
Eligible capital expenditures	7	348,000
		$15,096,000

The Canadian tax breakdown of distributions for the 2007 taxation year is as follows:

	Percentage
Taxable Income (Other Income)	91.45
Return of Capital	8.55
	100.00

With respect to cash distributions paid during the year to U.S. individual unitholders, 7.9 percent should be reported as a return of capital (to the extent of the Unitholder's U.S. tax basis in their respective units) and 92.1 percent should be reported as qualified dividends.

During the fourth quarter the Trust reported a future tax recovery of $133,000 compared to a future tax recovery of $1,110,000 in the third quarter. The difference of $977,000 relates to the significant increase in the adjusted distribution base to $15,842,000 (Q3 – $13,149,000) as well as increased capital spending of $7,213,000 (Q3 – $2,763,000) while only increasing the Trust's debt level by $828,000. The impact of the above was that the corporate subsidiaries had to claim maximum CDE and tangible tax pools deductions as well as reducing their loss carryforwards during the fourth quarter to cover the additional income left in the subsidiaries.

Net Earnings

The Trust's net earnings of $30,350,000 for the year ended December 31, 2007 represents a decrease of $6,990,000 over the Trusts 2006 net earnings of $37,250,000. The Trust recorded net earnings per unit on a fully diluted bases in 2007 of $1.79 verses $2.21 in the 2006 year. This represents a return on Unitholders' equity of approximately 68.6 (2006 – 69.8) percent based on year end Unitholders' equity.

The enacting of the trust taxation legislation resulted in a one time adjustment of $4,076,000 for future income tax expense which is the predominant reason for the decline in net earnings. Strong crude oil prices along with a 4.4 percent increase in production volumes were offset with a 10.6 percent decrease in the price of natural gas, increased operating costs and depletion claims due to higher production volumes and increased interest costs. The Trust returned in excess of 33 percent of its gross realized revenues in net earnings. The Trust's low capital costs combined with a low debt to adjusted distribution base ratio all contribute to the high return. Bonterra's higher than industry average per unit operating costs are more than offset with its low royalty rates resulting in one of the highest cash net backs in the industry (see cash netback).

Comprehensive Income

On January 1, 2007 the Trust became obliged to adopt the new accounting standards regarding the accounting for financial instruments. On adoption the Trust increased its investment in related party by $1,836,000 for the fair value of this investment. On January 1, 2007 the Trust further recognized a current asset of $1,189,000 for the fair value of its commodity derivative contracts. These adjustments resulted in a further increase in the future income tax liability and accumulated other comprehensive income of $645,000 and $2,380,000 respectively.

Other comprehensive income for 2007 included an increase in the unrealized gain on investment in a related party of $1,465,000 ($295,000 in the fourth quarter), a reduction of $814,000 relating to the recognition and transfer of previously reported hedging gains in accumulated other comprehensive income. Effective October 1, 2007, the Trust discontinued the use of hedge accounting due to the difficulty in determining the effective portion of the commodity hedges. All of the above adjustments are net of applicable income tax effects.

Standardized Distributable Cash

Compliance with Guidance

The following Management, Discussion and Analysis is in all material respects in accordance with the recommendations provided in CICA's *publication Standardized Distributable Cash in Income Trusts and Other Flow-Through Entities: Guidance on Preparation and Disclosure.*

Definition and Disclosure of Standardized Distributable Cash

	Year Ended December 31, 2007	Year Ended December 31, 2006	Cumulative Amounts From Inception of Trust (July 1, 2001 to December 31, 2007)
Cash Flow from Operating Activities	$51,433,000	$51,944,000	$218,275,000
Less adjustment for:			
Capital expenditures	(19,300,000)	(37,598,000)	(94,498,000)
Financing restrictions caused by debt	–	–	–
Standardized Distributable Cash	$32,133,000	$14,346,000	$123,777,000

Definition and Disclosure of Adjusted Distribution Base (Formerly Funds Flow from Operations)

	Year Ended December 31, 2007	Year Ended December 31, 2006	Cumulative Amounts From Inception of Trust (July 1, 2001 to December 31, 2007)
Standardized Distributable Cash – per above	$32,133,000	$14,346,000	$123,777,000
Adjusted for:			
Capital expenditures	19,300,000	37,598,000	94,498,000
Gain on sale of property	–	532,000	1,089,000
Changes in accounts receivable	1,082,000	147,000	5,576,000
Changes in crude oil inventory	(51,000)	7,000	253,000
Changes in parts inventory	18,000	(107,000)	(190,000)
Changes in prepaid expenses	244,000	305,000	498,000
Changes in accounts payable and accrued liabilities	269,000	(793,000)	1,863,000
Asset retirement obligations settled	820,000	762,000	2,529,000
Adjusted Distribution Base (formerly Funds Flow from Operations) (1)	$53,815,000	$52,797,000	$229,893,000

(1) Adjusted distribution base (formerly funds flow from operations) is not a recognized measure under GAAP. The Trust believes that in addition to net earnings, adjusted distribution base 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 adjusted distribution base as funds provided by operations before changes in non-cash operating working capital items excluding gain on sale of property and asset retirement obligations.

Working Capital Policies

The Trust, excluding the current portion of debt, maintains a consistent level of working capital. All items of working capital are generally turned over every 30 to 60 days. Excluding minor variations due to payment of bonuses and property taxes there are no reoccurring items that would cause a material seasonality impact in working capital.

Analysis of Relationship between Standardized Distributable Cash, Distributions, and Investing and Financing Activities

	Year ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2005
Standardized Distributable Cash	$32,133,000	$14,346,000	$23,413,000
Distributions	($44,648,000)	($47,281,000)	($38,949,000)
Increase in bank debt	$12,043,000	$25,202,000	$11,717,000
Proceeds on exercise of employee unit options	$993,000	$5,161,000	$2,823,000
Issuance of units (net of costs of issue)	–	–	($259,000)
Non cash financing and investing working capital adjustments	($521,000)	$2,572,000	$1,255,000

The only unfunded operating transaction of the Trust is its asset retirement obligations. The Trust has the following estimated timing of expenditures for asset retirement obligations:

Year	Expected Expenditure
2008	$296,000
2009	517.000
2010	529,000
2011	563,000
2012	856,000
	$2,761,000

Definition and History of Productive Capacity and Strategy

Bonterra's primary objective is to grow its reserves from which it expects to generate cash flow so it will be able to continue with distributions for its unitholders. The Trust defines Productive Capacity Maintenance as the maintaining of the Trusts proven plus probable reserves. The Trust follows a policy of internal development as its primary method of planned growth. Bonterra has a significant inventory of undrilled Cardium oil infill drilling locations as well as several shallow gas opportunities on its lands or through farm-in agreements. It is management's view that the calculation of the amount required for Productive Capacity Maintenance is the amount of reserves produced in the relevant time period multiplied by the Trust's finding and development costs for proven plus probable reserves. For this purpose the Trust believes that the use of a three year average rate is reasonable given fluctuations in annual costs due to market conditions.

	Year ended December 31, 2007	Year ended December 31, 2006	Year ended December 31, 2005
Proven and probable reserves at beginning of period (BOE's)	26,476,000	23,870,000	19,711,000
Reserves added due to acquisitions (net of disposals) (BOE's)	(421,000)	16,000	2,393,000
Reserves added due to capital expenditures (BOE's)	2,806,000	4,082,000	3,100,000
Production during period (BOE's)	1,540,000	1,476,000	1,334,000
Increase in productive capacity (BOE's)	845,000	2,622,000	4,159,000
Reserves per unit (fully diluted)	1.62	1.57	1.46
Productive capacity maintenance requirements	$17,043,000	$17,472,000	$9,205,000
Capital expenditures for the period	$19,300,000	$38,348,000	$56,703,000
Capital expenditures in excess of maintenance requirements	$2,257,000	$20,876,000	$47,498,000
Cost of increased productive capacity (per BOE)	$2.67	$8.01	$11.42

Financing Strategy

The Trust maintains a strategy of limiting its debt levels to approximately one year adjusted distribution base. Bonterra has a long term goal to retain between 20 to 25 percent of its adjusted distribution base to finance its capital maintenance expenditures. Over the past years, this level of retention of adjusted distribution base has proven to be sufficient to maintain the productive capacity of the Trust. To the extent additional capital expenditures are incurred to increase reserves, the Trust anticipates financing them through proceeds received on exercise of employee unit options, equity placements or from its line of credit.

Periods may exist where the cost of replacing reserves exceed the level of funds withheld. However, the Trust with its long life reserves and relatively low debt levels compared to other income trusts has the flexibility to increase or decrease its capital commitments depending on commodity prices and costs of development.

It is management's strategy to finance the costs of reclamation as well as potential income taxes (commencing in 2011) resulting from the recently enacted income trust tax law from the adjusted distribution base. Management is reviewing various organizational alternatives and operational strategies to mitigate the impact of the new tax.

Compliance with Financial Covenants

Due to the relatively low debt levels maintained by the Trust, the Trust's loan agreements do not contain any debt covenants other than that the debt is payable upon demand.

Per Unit and Ratio Disclosures

	Year Ended December 31, 2007	Year Ended December 31, 2006	Cumulative Amounts From Inception of Trust (July 1, 2001 to December 31, 2007)
Standardized Distributable Cash	$32,133,000	$14,346,000	$123,777,000
Per weighted average unit	$1.90	$0.86	$8.01
Per fully diluted unit	$1.90	$0.85	$7.96
Cash distributions	$44,648,000	$47,281,000	$204,299,000
Payout ratio	1.39	3.30	1.65
Adjusted Distribution Base	$53,815,000	$52,797,000	$229,893,000
Per weighted average unit	$3.18	$3.15	$14.93
Per fully diluted unit	$3.18	$3.12	$14.82
Cash distributions	$44,648,000	$47,281,000	$204,299,000
Payout ratio	0.83	0.90	0.89

On a go forward basis the Trust plans to reduce the payout ratio in respect of Standardized Distributable Cash to a level between 110 to 120 percent to facilitate a debt to adjusted distribution base level of approximately one year and to incur no current income tax (excluding Saskatchewan Resource Surcharge). This will be attained through continued control of capital replacement costs, by examining lower cost methods of reserve replacement as well as increased cash flow from wells currently producing.

Tax Attributes of Distributions and the Trust's Assets

See discussion under Income Taxes.

Cash Netback

The following table illustrates the Trust's cash netback:

$ per Barrel of Oil Equivalent (BOE)	2007	2006
Production volumes (BOE)	1,539,461	1,475,639
Gross production revenue	$ 62.64	$ 60.13
Royalties	(8.08)	(7.12)
Field operating	(15.64)	(15.07)
Field netback	38.92	37.94
General and administrative	(1.69)	(1.56)
Interest and taxes	(2.30)	(1.34)
Cash netback	$ 34.93	$ 35.04

The following table illustrates the Trust's cash netback for the three months ended:

$ per Barrel of Oil Equivalent (BOE)	**December 31 2007**	**September 30 2007**
Production volumes (BOE)	395,154	375,962
Gross production revenue	$ 67.25	$ 63.29
Royalties	(8.39)	(7.13)
Field operating	(14.01)	(17.02)
Field netback	44.85	39.14
General and administrative	(1.87)	(2.06)
Interest and taxes	(2.89)	(2.12)
Cash netback	$ 40.09	$ 34.96

Finding and Development Costs (F&D Costs)

Bonterra has been active in its capital development program over the past three years. Over this time period the Trust has incurred the following finding and development costs:

	2007 F&D Costs per BOE (1)(2)	**2006 F&D Costs per BOE (1) (2)**	**2005 F&D Costs per BOE (1) (2)**	**2007 Three Year Average**	**2006 Three Year Average**
Proved Reserve Additions	$2.74	$25.51	$14.86	$14.37	$15.90
Proved plus Probable Reserve Additions	$2.68	$18.21	$12.33	$11.07	$11.84

The above figures have been calculated in accordance with National Instrument 51-101 (NI 51-101) where the finding and development costs equate to the total exploration and development costs incurred by the Trust during the year plus the yearly change in estimated future development costs as calculated by Sproule Associates Limited. The following precautionary notes have been provided as required by NI 51-101.

(1) BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6MCF:1bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

During 2007, Bonterra experienced an approximate 30 percent reduction in drilling and completion costs. In addition, results from the Trust's Cardium oil drilling program have been better than anticipated resulting in an increase in the third party engineering reports estimated recoverable reserves from existing wells but also from future development. Both these factors contributed to an overall F&D cost in 2007 of $2.68 per proven and probable reserve.

Related Party Transactions

The Trust holds 689,682 (2006 – 689,682) common shares in Comaplex which have a fair market value as of December 31, 2007 of $4,014,000 (2006 – $2,297,000). Comaplex is a publically traded mineral company on the Toronto Stock Exchange. The Trust's ownership in Comaplex represents approximately 1.5 percent of the issued and outstanding common shares of Comaplex. Bonterra has common directors and management with Comaplex.

Comaplex paid a management fee to Bonterra Corp. of $300,000 (2006 – $300,000). Comaplex also cost shares office rental costs and reimburses Bonterra Corp. for costs related to employee benefits and office materials. In addition

Comaplex owns 204,633 (December 31, 2006 – 204,633) units in the Trust. Services provided by Bonterra Corp. include executive services (president and vice president, finance duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. At December 31, 2007, Comaplex owed the Trust $63,000 (December 31, 2006 – $38,000).

The Trust also has a management agreement with Pine Cliff. Pine Cliff has common directors and management with the Trust. Pine Cliff trades on the TSX Venture Exchange. Pine Cliff paid a management fee to Bonterra Corp. of $216,000 (2006 – $216,000). Services provided by Bonterra Corp. include executive services (president and vice president, finance duties), accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. The Trust has no share ownership in Pine Cliff. As at December 31, 2007 the Trust had an account receivable from Pine Cliff of $4,000 (December 31, 2006 – $Nil).

Commitments

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
Office lease	$1,658,000	$289,000	$932,000	$437,000

Financial Reporting Update

During 2007, the Trust completed the implementation of the new CICA Handbook Section 3855, Financial Instruments – Recognition and Measurement, Section 1530, Comprehensive Income and Section 3865, Hedges that deal with the recognition and measurement of financial instruments at fair value and comprehensive income. See notes 1 and 8 in the Notes to the audited Consolidated Financial Statements for further details.

Accounting Changes

Section 1506 permits voluntary changes in accounting policy only if they result in financial statements that provide more reliable and relevant information. Changes in policy are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including these changes in net income. In addition, disclosure is required for all future accounting changes when an entity has not applied a new source of GAAP that has been issued but is not yet effective.

Future Accounting Changes

On December 1, 2006, the CICA issued three new accounting standards: Handbook Section 1535, Capital Disclosures, Section 3862, Financial Instruments – Disclosure, and Section 3863, Financial Instruments – Presentation. These new standards will be effective January 1, 2008.

Section 1535 specifies the disclosure of an entity's objectives, policies and processes for managing capital, quantitative data about what the entity regards as capital, whether the entity has complied with any capital requirements, and if it has not complied, the consequences of such non-compliance. This Section is expected to have minimal impact on the Trust's financial statements.

Sections 3862 and 3863 specify a revised and enhanced disclosure on financial instruments. Increased disclosure will be required on the nature and extent of risks arising from financial instruments and how the entity manages those risks.

In February 2008, the CICA issued Section 3064, Goodwill and Intangible Assets, replacing Section 3062, Goodwill and Other Intangible Assets and Section 3450, Research and Development Costs. Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Trust will adopt the new standards for its fiscal year beginning January 1, 2009. This standard establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section on its consolidated financial statements. (The Trust does not expect that the adoption of this new Section will have a material impact on its consolidated financial statements.)

Liquidity and Capital Resources

During 2007 the Trust participated in drilling 24 gross (16 net) wells at a total cost of $18,595,000. Included in the above figure is approximately $7,000,000 of costs associated with the completion and tie-in of wells the Trust drilled in 2006 and prior years. An additional $1,200,000 was spent in 2008 to complete and tie-in the remaining 2007 drilled wells for an average cost of $760,000 per well. This compares to over $1.1 million per Cardium well in 2006.

As at December 31, 2007 Bonterra had 7 gross (6.3 net) Cardium oil wells, 2 gross (2 net) natural gas wells and 3 gross (2.5 net) CBM wells drilled but not on production. Subsequent to December 31, 2007 and up to the date of this report, Bonterra has put on production all the Cardium oil wells and 1 gross (1 net) shallow gas well. The timing for the eventual tie-in of the remaining natural gas and CBM wells has not yet been determined.

The Trust currently has plans to drill 25 gross (20 net) infill Cardium wells at an estimated budget figure of $800,000 per well. The Trust also plans on refracing 10 to 15 Cardium wells in 2008 to enhance current production. In addition, the Trust is currently examining an infill Edmonton Sand natural gas program. Total capital costs are anticipated to be approximately $20,000,000 for the planned development programs and tying in of the remaining 2007 drilled wells. The Trust anticipates funding the 2008 capital program out of current cash flow and exercising of employee unit options. This combination should allow for the Trust to maintain its debt to adjusted distribution base ratio at less than one.

The Trust is continuing with its efforts to acquire producing and non producing properties through either property or entity acquisitions. Funding for any acquisition would depend on items such as the type of acquisition (entity vs. property), quality of the assets, size of the purchase and the Trust unit trading price at the time of the acquisition.

At December 31, 2007 the Trust had bank debt of $57,422,000 (2006 – $45,379,000). The Trust through its operating subsidiaries has bank revolving credit facilities totalling $69,900,000 at December 31, 2007 (December 31, 2006 – $49,900,000). 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 $355,000 at December 31, 2007 (2006 - $340,000). Security for the credit facility consists of various fixed and floating demand debentures totalling $79,000,000 over all of the Trust's assets, and a general security agreement with first ranking over all personal and real property. As the Trust maintains a low debt to adjusted distribution base ratio and also has a substantial asset value (see review of operations), the Trust's banker does not require any financial statement ratio or other debt covenants other than those described above.

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.

	2007		2006	
Issued	**Number**	**Amount**	**Number**	**Amount**
Trust Units				
Balance, beginning of year	16,874,658	$89,488,000	16,535,138	$83,900,000
Transfer of contributed surplus to unit capital	–	109,000	–	427,000
Issued pursuant to Trust unit option plan	53,500	993,000	339,500	5,161,000
Balance, end of year	16,928,158	$90,590,000	16,874,658	$89,488,000

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,692,800 (2006 – 1,687,500) 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, 2007 and 2006, and changes during the years ending on those dates is presented below:

	2007		2006	
	Options	**Weighted-Average Exercise Price**	**Options**	**Weighted-Average Exercise Price**
Outstanding at beginning of year	721,500	$26.55	646,000	$18.67
Options granted	553,000	28.11	447,000	29.18
Options exercised	(53,500)	18.56	(339,500)	15.20
Options cancelled	(44,000)	27.92	(32,000)	24.70
Outstanding at end of year	1,177,000	$27.59	721,500	$26.55
Options exercisable at end of year	530,000	$26.63	212,500	$22.62

The following table summarizes information about unit options outstanding at December 31, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Number Outstanding At 12/31/07**	**Weighted-Average Remaining Contractual Life**	**Weighted-Average Exercise Price**	**Number Exercisable At 12/31/07**	**Weighted-Average Exercise Price**
$22.45-$23.35	225,000	1.4 years	$23.34	225,000	$23.34
$24.20-$27.50	32,000	2.3 years	25.30	–	–
$28.70-$28.75	880,000	1.6 years	28.49	285,000	28.75
$32.00-$33.75	40,000	2.0 years	33.55	20,000	33.55
$22.45-$33.75	1,177,000	1.6 years	$27.59	530,000	$26.63

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 27 percent of its estimated 2008 production on a BOE basis. The Trust uses a combination of fixed price swaps as well as no cost collars to protect against commodity price declines.

Taxation of Trusts

In June, 2007 the October 31, 2006 proposals by the Minster of Finance for Canada for the taxation of existing income trusts were proclaimed into law. In summary the law provides that:

1. An income trust will be subject to a special rate of tax on its distributions of income that is attributable to income from business carried on in Canada, income from non-portfolio investments in Canadian resource properties, and capital gains from the above.
2. Distributions from income trusts will be taxed in the same manner as a dividend from a taxable Canadian corporation.
3. For existing trusts the new rules apply to taxation years that end after 2010.
4. The tax rate that would apply to taxation years after 2010 would be 31.5 percent. In October of 2007 the Minister of Finance announced a reduction in this rate to 29.5 percent for 2011 and 28 percent thereafter.

In addition the Minister announced in October 2006 the government's attempt to limit the growth of existing income trusts. According to the announcement, the government will not recommend any change to the 2011 date in respect of any income trust whose equity capital grows as a result of issuances of new equity, in any of the years from October 31, 2006 to December 31, 2010 by an amount that does not exceed the greater of $50 million and an objective “safe harbour” amount. The safe harbour amount is measured by reference to the trust's market capitalization as of the end of trading on October 31, 2006. Market capitalization is to be measured in terms of the value of an income trust's issued and outstanding publicly-traded units and its bank debt. For the period November 1, 2006 to December 31, 2007 an income trusts safe harbour will be 40 percent of that October benchmark and 20 percent for each calendar year 2008, 2009 and 2010. The Minister also announced in October 2006 the government's intent to allow for conversions of income trusts back to corporate form as well as to allow the mergers of income trusts without effecting the above safe harbour amounts. None of the rules surrounding the safe harbour and conversion to a corporate form have been legislated.

The impact to individual unitholders of the above legislative changes differs by the category of the investor. For Canadian individual or Canadian taxable corporation investors the distributions will be subject to the dividend tax credit which should offset to a large degree the tax paid by the Trust. For those investors that hold their trust units in a tax deferred fund (RRSP's, RRIF's or in a pension fund) there will be double taxation of distributions. This will result in an effective rate of tax in most cases in excess of 50 percent, twenty nine and a half percent (twenty eight percent in 2012 and thereafter) at the trust level and a further tax on withdrawal from the fund based on the individual's tax rate. Also for non-resident investors there will be a significant double taxation as well. The trust again pays its taxes, then generally a further 15 percent withholding is required and the non-residents must also pay their own taxes in their country of residence. This could result in excess of 55 percent being paid in taxes.

The Trust's management along with its professional advisors have been examining various options available to it to in respect of its long term strategic planning. The process continues to be complicated by the fact that significant proposals of the Ministers October 2006 announcement have not yet been legislative. In addition, the Trust has a diverse ownership base with approximately 24.8 percent of outstanding units held by non-residents as of January 2, 2008 (based on ADP Canada and ADP USA beneficial reports) and an estimated 15 percent held by deferred income plans with the rest held by taxable Canadian investors.

In the mean time the proposed safe harbour rules will allow Bonterra to raise in excess of $650,000,000 over the next three years without loosing its tax free status before 2011. This will allow the trust to continue with its Cardium infill drilling program, its shallow natural gas and CBM development as well as potentially developing a CO_2 flood program or to make corporate or property acquisitions. The current emphasis will be placed on increasing the Trusts available tax pools to assist in dealing with the future tax consequences resulting from the taxation of trust legislation.

Sensitivity Analysis

Sensitivity analysis, as estimated for 2008:

	Cash Flow	Cash Flow Per Unit
U.S. $1.00 per barrel	$ 958,000	$0.056
Canadian $0.10 per MCF	$ 213,000	$0.013
Change of Canadian $0.01/U.S. $ exchange rate	$ 692,000	$0.041

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	Garth E. Schultz
President and CEO	Vice President, Finance and CFO
March 14, 2008	March 14, 2008

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, 2007 and 2006 and the consolidated statements of Unitholders' equity, operations and deficit, and cash flow for the years then ended and the consolidated statement of comprehensive income for the year ended December 31, 2007. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these 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, 2007 and 2006 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 14, 2008	Chartered Accountants

Bonterra Energy Income Trust

Consolidated Balance Sheets

As at December 31	2007	2006
Assets		
Current		
Accounts receivable (Note 9)	**$ 10,575,000**	$ 10,486,000
Crude oil inventory	**792,000**	843,000
Parts inventory	**132,000**	114,000
Prepaid expenses	**1,330,000**	1,086,000
Future income tax asset (Note 5)	**913,000**	–
Investment in related party (Note 2)	**4,014,000**	461,000
	17,756,000	12,990,000
Property and Equipment (Note 3)		
Petroleum and natural gas properties and related equipment	**187,288,000**	176,602,000
Accumulated depletion and depreciation	**(61,805,000)**	(54,650,000)
	125,483,000	121,952,000
	$143,239,000	$134,942,000
Liabilities		
Current		
Distribution payable	**$ 3,724,000**	$ 4,050,000
Accounts payable and accrued liabilities	**12,291,000**	13,748,000
Derivative liability (Note 11)	**3,085,000**	–
Debt (Note 4)	**57,422,000**	45,379,000
	76,522,000	63,177,000
Future income tax liability (Note 5)	**7,595,000**	3,587,000
Asset retirement obligations (Note 6)	**14,904,000**	14,819,000
	99,021,000	81,583,000
Commitments, Contingencies and Guarantees (Note 11)		
Unitholders' Equity (Note 7)		
Unit capital	**90,590,000**	89,488,000
Contributed surplus	**2,140,000**	1,116,000
	92,730,000	90,604,000
Deficit	**(51,543,000)**	(37,245,000)
Accumulated other comprehensive income (Note 8)	**3,031,000**	–
	(48,512,000)	(37,245,000)
Total Unitholders' Equity	**44,218,000**	53,359,000
	$143,239,000	$134,942,000

On behalf of the Board:

Director

Director

Bonterra Energy Income Trust

Consolidated Statements of Unitholders' Equity

For the Years Ended December 31	**2007**	2006
Unitholders' equity, beginning of year	**$53,359,000**	$57,322,000
Comprehensive income for the year	**31,001,000**	37,250,000
Adjustment of opening accumulated other comprehensive income *(Note 1)*	**2,380,000**	–
Net capital contributions *(Note 7)*	**993,000**	5,161,000
Unit option based compensation adjustment	**1,133,000**	907,000
Distributions declared	**(44,648,000)**	(47,281,000)
Unitholders' Equity, End of Year	**$44,218,000**	$53,359,000

Bonterra Energy Income Trust

Consolidated Statements of Operations and Deficit

For the Years Ended December 31	**2007**	2006
Revenue		
Oil and gas sales	**$95,810,000**	$88,796,000
Realized gain (loss) on risk management contracts	**621,000**	(62,000)
Unrealized loss on risk management contracts *(Notes 8 and 11)*	**(3,085,000)**	–
Royalties	**(12,444,000)**	(10,512,000)
Alberta royalty tax credit	**–**	487,000
Gain on sale of property (Note 3)	**–**	532,000
Interest and other	**44,000**	66,000
	80,946,000	79,307,000
Expenses		
Production costs	**24,073,000**	22,238,000
General and administrative	**2,603,000**	2,295,000
Interest on debt	**3,028,000**	1,610,000
Unit option based compensation	**1,133,000**	907,000
Dry hole costs	**3,078,000**	2,919,000
Depletion, depreciation and accretion	**13,597,000**	12,474,000
	47,512,000	42,443,000
Earnings Before Taxes	**33,434,000**	36,864,000
Taxes (recovery) (Note 5)		
Current	**512,000**	367,000
Future	**2,572,000**	(753,000)
	3,084,000	(386,000)
Net Earnings for the Year	**30,350,000**	37,250,000
Deficit, beginning of year	**(37,245,000)**	(27,214,000)
Distributions declared	**(44,648,000)**	(47,281,000)
Deficit, end of year	**($51,543,000)**	($37,245,000)
Net Earnings Per Trust Unit – Basic (Note 7)	**$ 1.79**	$ 2.23
Net Earnings Per Trust Unit – Diluted (Note 7)	**$ 1.79**	$ 2.21

Bonterra Energy Income Trust

Consolidated Statement of Comprehensive Income (Note 1)

For the Year Ended December 31	**2007**
Net Earnings for the Period	**$30,350,000**
Other comprehensive income, net of income tax	
Unrealized gains on investments (net of income taxes of $252,000)	**1,465,000**
Gains and losses on derivatives designated as cash flow hedges transferred to net earnings (net of income taxes of ($334,000))	**(814,000)**
Other Comprehensive Income	**651,000**
Comprehensive Income	**$31,001,000**
Comprehensive Income Per Trust Unit – Basic (Note *7*)	**$ 1.83**
Comprehensive Income Per Trust Unit – Diluted (Note *7*)	**$ 1.83**

Bonterra Energy Income Trust

Consolidated Statements of Cash Flow

For the Years Ended December 31	**2007**	2006
Operating Activities		
Net earnings for the year	**$30,350,000**	$37,250,000
Items not affecting cash		
Gain on sale of property	**–**	(532,000)
Unrealized loss on risk management contracts	**3,085,000**	–
Unit option based compensation	**1,133,000**	907,000
Dry hole costs	**3,078,000**	2,919,000
Depletion, depreciation and accretion	**13,597,000**	12,474,000
Future income taxes (recovery)	**2,572,000**	(753,000)
	53,815,000	52,265,000
Change in non-cash working capital		
Accounts receivable	**(1,082,000)**	(147,000)
Crude oil inventory	**51,000**	(7,000)
Parts inventory	**(18,000)**	107,000
Prepaid expenses	**(244,000)**	(305,000)
Accounts payable and accrued liabilities	**(269,000)**	793,000
Asset retirement obligations settled	**(820,000)**	(762,000)
	(2,382,000)	(321,000)
	51,433,000	51,944,000
Financing Activities		
Increase in debt	**12,043,000**	25,202,000
Unit option proceeds	**993,000**	5,161,000
Unit distributions	**(44,974,000)**	(46,869,000)
	(31,938,000)	(16,506,000)
Investing Activities		
Property and equipment expenditures	**(19,300,000)**	(38,348,000)
Proceeds on sale of property	**–**	750,000
Change in non-cash working capital		
Accounts receivable	**993,000**	681,000
Accounts payable and accrued liabilities	**(1,188,000)**	1,479,000
	(19,495,000)	(35,438,000)
Net cash inflow	**–**	–
Cash, beginning of year	**–**	–
Cash, End of Year	**$ –**	$ –
Cash Interest Paid	**$ 3,028,000**	$ 1,610,000
Cash Taxes Paid	**$ 292,000**	$ 393,000

Bonterra Energy Income Trust

Notes to the Consolidated Financial Statements

For the Years Ended December 31, 2007 and 2006

1. SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") as described below.

Consolidation

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

Measurement Uncertainty

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used in ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserve estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and facilities and the estimated period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the financial statements of future periods.

Financial instruments – recognition and measurement

On January 1, 2007, the Trust adopted Section 3855 of the Canadian Institute of Chartered Accountants' ("CICA") Handbook, "Financial Instruments – Recognition and Measurement" and Section 3861 "Financial Instruments – Disclosure and Presentation." These set out the standards for recognizing and measuring financial instruments in the balance sheet and the standards for reporting gains and losses in the financial statements. Financial assets available for sale, assets and liabilities held for trading and derivative financial instruments, whether part of a hedging relationship or not, have to be measured at fair value.

The Trust has made the following classifications:

- Investment in related party is classified as available for sale, and recorded at fair value which is marked-to-market through comprehensive income.
- Accounts receivable are classified as loans and receivables and are recorded at amortized cost using the effective

interest method. Gains and losses are recognized in net earnings when the asset is no longer recognized.

- Accounts payable and accrued liabilities and bank debt are classified as other liabilities and are recorded at amortized cost using the effective interest method. Gains and losses are recognized in net earnings when the liability is no longer recognized.

The adoption of the Sections is done retrospectively without restatement of the consolidated financial statements of prior periods. As at January 1, 2007, the impact on the consolidated balance sheet of measuring the investment in related party at fair value was an increase of $1,836,000 to investment in a related party, an increase in future income tax liability of $270,000 and an increase in accumulated other comprehensive income of $1,566,000.

The impact on the consolidated balance sheet of measuring hedging derivatives at fair value as at January 1, 2007 was an increase in other assets of $1,189,000, an increase in future tax liability of $375,000 and an increase in accumulated other comprehensive income of $814,000. As of October 1, 2007, the Trust discontinued the use of hedge accounting (see Note 8).

The Trust selected January 1, 2003 as its transition date for embedded derivatives. An embedded derivative is a component of a financial instrument or another contract the characteristics of which are similar to a derivative. This had no impact on the consolidated financial statements.

Comprehensive income

On January 1, 2007, the Trust adopted Section 1530 of the CICA Handbook, "Comprehensive Income." This section describes reporting and disclosure recommendations with respect to comprehensive income and its components. Comprehensive income is the change in unitholders' equity, which results from transactions and events from sources other than the Trust's unitholders and consists of net income and other comprehensive income ("OCI"). OCI comprises revenues, expenses, gains and losses that are recognized in comprehensive income but excluded from net income. Such items include unrealized gains and losses from changes in fair value of certain financial instruments.

The adoption of this section results in the Trust now presenting a consolidated statement of comprehensive income as a part of the consolidated financial statements.

Equity

On January 1, 2007, the Trust adopted Section 3251 of the CICA Handbook "Equity" replacing Section 3250 "Surplus." This section describes standards for the presentation of equity and changes in equity for reporting periods as a result of the application of Section 1530 "Comprehensive Income".

Hedges

On January 1, 2007, the Trust adopted Section 3865 of the CICA Handbook "Hedges." The recommendations of this Section expand the guidelines required by Accounting Guideline 13 (AcG-13), Hedging Relationships. This section describes when and how hedge accounting can be applied as well as the disclosure requirements. Hedge accounting enables the recording of gains, losses, revenues and expenses from the derivative financial instrument in the same period as those related to the hedged item.

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.

Accounting changes

The Trust also adopted Section 1506, "Accounting Changes," whereby the only impact is to provide disclosure of when an entity has not applied a new source of GAAP that has been issued but is not yet effective. This is the case with Section 1535, "Capital Disclosures", Section 3862, "Financial Instruments Disclosures" and Section 3863, "Financial Instruments – Presentation" which are required to be adopted for fiscal years beginning on or after October 1, 2007. The Trust will adopt these standards on January 1, 2008 and it is expected that the only effect on the Trust will be incremental disclosures regarding the Trusts objectives, policies and processes for managing capital and the significance of financial instruments for the entity's financial position and performance; and the nature, extent and management of risks arising from financial instruments to which the entity is exposed.

In February 2008, the CICA issued Section 3064, "Goodwill and Intangible Assets," replacing Section 3062, "Goodwill and Other Intangible Assets" and Section 3450, "Research and Development Costs." Various changes have been made to other sections of the CICA Handbook for consistency purposes. The new section will be applicable to financial statements relating to fiscal years beginning on or after October 1, 2008. Accordingly, the Trust will adopt the new standards for its fiscal year beginning January 1, 2009. This standard establishes standards for the recognition, measurement, presentation and disclosure of goodwill subsequent to its initial recognition and of intangible assets by profit-oriented enterprises. Standards concerning goodwill are unchanged from the standards included in the previous Section 3062. The Trust is currently evaluating the impact of the adoption of this new Section on its consolidated financial statements. The Trust does not expect that the adoption of this new Section will have a material impact on its consolidated financial statements.

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 fair value. In 2006 the investments were recorded at 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 exploratory wells are initially capitalized pending determination of proved reserves. Costs of wells which are assigned proved reserves remain capitalized, while costs of unsuccessful wells are charged to earnings. All other exploration costs including geological and geophysical costs are charged to earnings as incurred. Development costs, including the cost of all wells, are capitalized.

Producing properties and significant unproved properties are assessed annually or more frequently as economic events dictate, for potential impairment. Impairment is assessed by comparing the estimated net undiscounted future cash flows to the carrying value of the asset. If required, the impairment recorded is the amount by which the carrying value of the asset exceeds its fair value.

Depreciation and depletion of capitalized costs of oil and gas producing properties are calculated using the unit of production method. Development and exploration drilling and equipment costs are depleted over the remaining proved developed reserves. Depreciation of other plant and equipment is provided on the straight line method. Straight line depreciation is based on the estimated service lives of the related assets which is estimated to be 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 Trust and its subsidiary companies in the consolidated financial statements of the Trust and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period in which the change occurs.

In the Trust structure, payments are made between the Trust's 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 Option Based Compensation

The Trust has a unit option based compensation plan, which is described in Note 7. 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.

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 to purchase trust units were exercised. The treasury stock method is used to determine the dilutive effect of trust unit options, 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.

2. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 (December 31, 2006 – 689,682) common shares in Comaplex Minerals Corp (Comaplex), a company with common directors and management with the Trust and its subsidiaries. The investment is recorded at fair market value (December 31, 2006 – $2,297,000). The common shares trade on the Toronto Stock Exchange under the symbol CMF. The investment represents less than a one and a half percent ownership in the outstanding shares of Comaplex.

3. PROPERTY AND EQUIPMENT

	2007		2006	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Undeveloped land	$ 316,000	$ –	$ 334,000	$ –
Petroleum and natural gas properties and related equipment	185,947,000	61,105,000	175,353,000	54,008,000
Furniture, equipment and other	1,025,000	700,000	915,000	642,000
	$187,288,000	$ 61,805,000	$176,602,000	$ 54,650,000

In January 2006 the Trust completed the sale of a non-operated oil and gas property for gross proceeds of $750,000 to an unrelated third party. The disposition resulted in the Trust reporting a gain on sale of $532,000.

4. DEBT

The Trust has a bank revolving credit facility of $69,900,000 at December 31, 2007 (2006 – $49,900,000). 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 $355,000 (December 31, 2006 – $340,000) were issued at December 31, 2007. Security for the credit facility consists of various fixed and floating demand debentures totalling $79,000,000 over all of the Trust's assets, and a general security agreement with first ranking over all personal and real property.

The credit facility carries an interest rate of Canadian chartered bank prime. The Trust has classified this debt as a current liability as required by GAAP. It has been management's experience that these types of demand 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, 2007 for this loan was $3,021,000 (2006 – $1,610,000).

5. TAXES

The Trust has recorded a future income tax liability and a current income tax asset related to assets and liabilities and related tax amounts. The following 2007 figures reflect the consequences of the Canadian Federal Government’s October 31, 2006 announcement on the future taxation of Income Trusts and the enactment of thse proposals in 2007:

	2007	2006
Future income tax liability related to assets and liabilities:	$11,517,000	$6,233,000
Future tax asset related to finance costs:	(79,000)	–
Future tax asset related to corporate tax losses carried forward in the subsidiary companies	(3,843,000)	(2,646,000)
Future income tax liability	$ 7,595,000	$3,587,000
Future income tax asset related to current portion of derivative liability	$ 913,000	$ –

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows and the federal government’s rate reduction enacted in December 2007:

	2007	2006
Earnings before income taxes	$33,434,000	$36,864,000
Combined federal and provincial income tax rates	32.27%	34.97%
Income tax provision calculated using statutory tax rates	10,789,000	12,891,000
Increase (decrease) in taxes resulting from:		
Saskatchewan resource surcharge	512,000	367,000
Unit-based compensation	366,000	317,000
Non-deductible crown royalties	–	1,072,000
Resource allowance	–	(1,901,000)
Change in effective tax rate of the Trust	4,076,000	–
Trust income allocated to Unitholders	(13,176,000)	(13,031,000)
Others	517,000	(123,000)
Income tax expense (recovery)	$ 3,084,000	$(386,000)

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	$16,921,000
Canadian oil and gas property expenditures	10	1,771,000
Canadian development expenditures	30	30,431,000
Canadian exploration expenditures	100	93,000
Income tax losses carried forward [1]	100	15,056,000
		$64,272,000

[1] Income tax losses carried forward expire in 2014 ($635,000), 2015 ($3,574,000), 2026 ($4,826,000) and 2027 ($6,021,000).

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	$14,409,000
Finance costs	20	339,000
Eligible capital expenditures	7	348,000
		$15,096,000

On October 31, 2006, the Canadian Federal Government announced a proposed Trust taxation pertaining to taxation of distributions paid by publicly traded income trusts and this was enacted by legislation in June, 2007. Previously, distributions paid to unitholders, other than returns of capital, were claimed as a deduction by the Trust in arriving at taxable income whereby tax is eliminated at the Trust level and tax is paid on the distributions by the unitholders. The June, 2007 legislation results in a two-tiered tax structure whereby distributions commencing in 2011 would first be subject to a 31.5 percent tax at the Trust level and then investors would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation. The tax rate was subsequently lowered to 29.5 percent in 2011 and 28 percent in 2012 and thereafter.

Prior to June 2007, the Trust estimated the future income tax on certain temporary differences between amounts recorded on its balance sheet for book and tax purposes at a nil effective tax rate. The entire balance of the future income tax liability reported related to assets and liabilities and related tax amounts held through the Trust's 100 percent held subsidiaries. Under the legislation, the Trust now estimates the effective tax rate on post-2010 reversal of these temporary differences at the above mentioned tax rates. Temporary differences at the Trust level reversing before 2011 will still give rise to nil future income taxes.

Based on its assets and liabilities as at December 31, 2007, the Trust has estimated the amount of its temporary differences which were previously not subject to tax and estimated the periods in which these differences will reverse. The Trust estimates that $14,496,000 net taxable temporary differences will reverse after January 1, 2011, resulting in an additional $4,076,000 future income tax liability. The taxable temporary differences relate principally to the excess of net book value of oil and gas properties over the remaining tax pools attributable thereto.

As the legislation gives rise to a change in the Trust's estimated future income tax liability in the period, the recognition of the additional liability is accounted for prospectively in the period and an additional $4,076,000 of future income tax expense has been recorded for the period.

While the Trust believes it will be subject to additional tax under the new legislation, the estimated effective tax rate on temporary difference reversals after 2011 may change in future periods. As the legislation is new, future technical interpretations of the legislation could occur and could materially affect management's estimate of the future income tax liability.

The amount and timing of reversals of temporary differences will also depend on the Trust's future operating results, acquisitions and dispositions of assets and liabilities, and distribution policy. A significant change in any of the preceding assumptions could materially affect the Trust's estimate of the future income tax liability.

6. ASSET RETIREMENT OBLIGATIONS

At December 31, 2007, the estimated total undiscounted amount required to settle the asset retirement obligations was $54,622,000 (2006 – $46,434,000). Costs for asset retirement have been calculated assuming a 2 percent inflation rate. These obligations will be settled based on the useful lives of the underlying assets, which extend up to 50 years into the future. This amount has been discounted using a credit-adjusted risk-free interest rate of 5 (2006 – 5) percent.

Changes to asset retirement obligations were as follows:

	2007	2006
Asset retirement obligations, January 1	$14,819,000	$13,195,000
Adjustment to asset retirement obligations	(399,000)	1,726,000
Adjustment related to asset additions (net of disposals)	563,000	–
Liabilities settled during the year	(820,000)	(762,000)
Accretion	741,000	660,000
Asset retirement obligations, December 31	$14,904,000	$14,819,000

7. UNIT CAPITAL

Authorized

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

	2007		2006	
Issued	Number	Amount	Number	Amount
Trust Units				
Balance, beginning of year	16,874,658	$89,488,000	16,535,138	$83,900,000
Transfer of contributed surplus to unit capital	–	109,000	–	427,000
Issued pursuant to Trust unit option plan	53,500	993,000	339,500	5,161,000
Balance, end of year	16,928,158	$90,590,000	16,874,658	$89,488,000

The number of trust units used to calculate diluted net earnings per unit for the year ended December 31, 2007 of 16,942,036 (2006 – 16,880,422) included the basic weighted average number of units outstanding of 16,908,266 (2006 – 16,737,651) plus 33,770 (2006 – 142,771) units related to the dilutive effect of unit options.

The deficit balance is composed of the following items:

	2007	2006
Accumulated earnings	$152,756,000	$122,406,000
Accumulated cash distributions	(204,299,000)	(159,651,000)
Deficit	($51,543,000)	($37,245,000)

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,692,800 (2006 – 1,687,500) 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, 2007 and 2006, and changes during the years is presented below:

	2007		2006	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of year	721,500	$26.55	646,000	$18.67
Options granted	553,000	28.11	447,000	29.18
Options exercised	(53,500)	18.56	(339,500)	15.20
Options cancelled	(44,000)	27.92	(32,000)	24.70
Outstanding at end of year	1,177,000	$27.59	721,500	$26.55
Options exercisable at end of year	530,000	$26.63	212,500	$22.62

The following table summarizes information about unit options outstanding at December 31, 2007:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 12/31/07	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 12/31/07	Weighted-Average Exercise Price
$22.45-$23.35	225,000	1.4 years	$23.34	225,000	$23.34
$24.20-$27.50	32,000	2.3 years	25.30	–	–
$28.70-$28.75	880,000	1.6 years	28.49	285,000	28.75
$32.00-$33.75	40,000	2.0 years	33.55	20,000	33.55
$22.45-$33.75	1,177,000	1.6 years	$27.59	530,000	$26.63

The Trust records compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. The Trust granted 553,000 (2006 – 447,000) unit options with an estimated fair value of $1,494,000 (2006 – $1,193,000) ($2.70 per option (2006 – $2.67 per option)) using the Black-Scholes option pricing model with the following key assumptions:

	2007	2006
Weighted-average risk free interest rate (%)	4.7	4.1
Expected life (years)	2.3	2.5
Weighted-average volatility (%)	27.2	27.0
Dividend yield 2007 and 2006	based on the percentage of distributions paid to the Unitholders during the year	

8. ACCUMULATED OTHER COMPREHENSIVE INCOME

	January 1, 2007 (Note 1)	Other Comprehensive Income	December 31, 2007
Unrealized gains on available for sale financial assets	$1,566,000	$1,465,000	$3,031,000
Unrealized gains and losses on derivatives designated as cash flow hedges	814,000	(814,000)	–
	$2,380,000	$ 651,000	$ 3,031,000

As of October 1, 2007, the Trust determined that its cash flow hedges on commodities described in Note 11 is no longer an effective hedge. Therefore the full loss in cash flow hedges has been transferred from accumulated other comprehensive income to net earnings.

9. RELATED PARTY TRANSACTIONS

The Trust received a management fee from Comaplex of $300,000 (2006 – $300,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses and represents the fair value of the services rendered.

As at December 31, 2007, the Trust had an account receivable from Comaplex of $63,000 (December 31, 2006 – $38,000).

The Trust received a management fee from Pine Cliff of $216,000 (2006 – $216,000) for management services and office administration. This fee has been included as a recovery in general and administrative expenses and represents the fair value of the services rendered.

As at December 31, 2007 the Trust had an account receivable from Pine Cliff of $4,000 (December 31, 2006 – $Nil).

10. FINANCIAL INSTRUMENTS

Fair Values

The Trust's financial instruments include accounts receivable, distribution payable, accounts payable and accrued liabilities and 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 that approximate fair value. Derivative financial instruments are recorded at fair value (See Note 1).

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 for a portion of its 2008 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
January 1, 2008 to June 30, 2008	Crude Oil	1,000 barrels	WTI	Floor of $73.00 and ceiling of $83.00 per barrel
July 1, 2008 to December 31, 2008	Crude Oil	500 barrels	WTI	Floor of $73.00 and ceiling of $80.68 per barrel
November 1, 2007 to March 31, 2008	Natural Gas	2,000 GJ's	AECO	Floor of $6.50 and ceiling of $10.37 per GJ

Subsequent to December 31, 2007 and up to the date of the financial statements the Trust has entered into the following commodity hedging transactions:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
July 1, 2008 to December 31, 2008	Crude Oil	500 barrels	WTI	Floor of $85.00 and ceiling of $104.80 per barrel
April 1, 2008 to October 31, 2008	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $7.60 per GJ

As at December 31, 2007 the fair value of the outstanding commodity hedging contracts was a net liability of $3,085,000 (December 31, 2006 – net asset $1,189,000).

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
Office lease	$1,658,000	$289,000	$932,000	$437,000

12. SUBSEQUENT EVENTS – DISTRIBUTIONS

Subsequent to December 31, 2007, the Trust declared distributions of $0.22 per unit payable on February 29 and $0.23 per unit payable on March 31, 2008 to Unitholders of record on February 15 and March 14, 2008 respectively. The distributions represent amounts related to January and February 2008 operations.

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

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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