Bonterra
Energy Income Trust

Q3

FOR THE PERIOD ENDED SEPTEMBER 30, 2006

INTERIM REPORT

HIGHLIGHTS

	Three Months Ended September 30		Nine Months Ended September 30	
	2006	2005	**2006**	2005
Financial ($000, except $ per unit)				
Revenue – oil and gas	**23,665**	20,533	**67,015**	54,085
Funds Flow from Operations (1)	**14,401**	12,209	**40,562**	32,090
Per Unit – Basic	**0.86**	0.75	**2.43**	1.96
Per Unit – Diluted	**0.85**	0.74	**2.40**	1.93
Net Earnings	**10,441**	9,309	**30,779**	23,550
Per Unit – Basic	**0.62**	0.57	**1.84**	1.44
Per Unit – Diluted	**0.62**	0.56	**1.82**	1.42
Cash Distributions per Unit	**0.72**	0.60	**2.10**	1.69
Capital Expenditures and Acquisitions (2)	**12,597**	3,130	**28,891**	45,724
Total Assets			**130,655**	101,088
Working Capital Deficiency (3)			**38,853**	10,920
Unitholders Equity			**60,387**	60,662
Operations				
Oil and NGL's				
Barrels Per Day	**3,024**	2,680	**3,007**	2,679
Average Price ($ per barrel)	**71.11**	64.48	**66.06**	57.44
Natural Gas				
MCF Per Day	**5,925**	5,692	**6,059**	5,601
Average Price ($ per MCF)	**6.95**	8.69	**7.54**	7.76
Total Barrels per Day	**4,012**	3,545	**4,017**	3,613

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

(2) Capital expenditures and acquisitions include the purchase of Novitas Energy Ltd. (Novitas) on January 7, 2005. The Trust issued 1,335,753 units at a value of $25 per unit plus paid $769,000 in cash for all the 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) Includes 100 percent of debt.

(4) 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following report dated November 7, 2006 is a review of the operations, current financial position and outlook for Bonterra Energy Income Trust ("Bonterra" or "the Trust") and should be read in conjunction with the unaudited financial statements for the nine months ended September 30, 2006, including the notes related thereto, and the audited financial statements for the fiscal year ended December 31, 2005, together with the notes related thereto.

Comments Pertaining to Taxation of Income Trusts

Most of Bonterra's Unitholders are now generally aware of the November 1, 2006 announcement by the Federal Government in which it advised that in four years time Trusts would become taxable and that all or at least a portion of taxes would be shifted from individuals to the Trusts.

A Notice of Ways and Means Motion was tabled November 1, 2006, by the Federal Government, but it did not include any details so at this time it is impossible to determine the impact for Bonterra.

From a general perspective there are things that are disconcerting. The Government announced, without any consultation with the Trusts that:

1. If there was consultation with industry, there could have been a leak.
2. That the Federal and Provincial Governments were losing corporate tax revenue which would affect their abilities to finance social programs.
3. That Trusts on a long-term basis are not good for Canada.

Bonterra's views with regard to these items are that:

(1) Corporations and Trusts must ensure that they employ people that do not disclose confidential information; therefore, governments should be able to do that as well;

(2) Last week the Federal Government disclosed that personal income tax revenue for 2005 and 2006 is billions of dollars higher than projected and they do not know the reason for it; one of the main reasons is likely due to the high personal taxation on distributions from Trusts that results in much larger revenue than what is lost from the reduction in corporate taxes; and

(3) Trusts are making a high contribution to Canada's economic growth, both directly and indirectly from reinvestments by Unitholders in this country.

From Bonterra's perspective, the Trust at this time will continue to operate as it has in the past and will focus on growing its operations and increasing distributions on a per Unit basis. Management cannot at the present time assess the full impact on Canadian Unitholders who own Units directly, or in RRSP's or tax sheltered funds, and on foreign ownership. Further assessments will be made after details are provided by the Government. As with most other Trusts, Bonterra will also be attempting to have individual and Association discussions with the Federal

Government to get a clearer understanding of the motivation for this process and be able to represent the facts about the Trust industry. For example, it is doubtful that the federal government intended to immediately trigger high capital gains if trusts convert to corporations because the new legislation in some instances now favor corporations over trusts. It is important that these types of issues are resolved.

General

Bonterra is pleased to report its results for the first nine months of 2006. The Trust's first nine month results show continued increases in revenue and funds flow. Funds flow from operations and net earnings increased by 26 and 31 percent respectively over the results from the first nine months of 2005.

Oil prices averaged $66.06 per barrel and natural gas prices averaged $7.54 per MCF for the nine month period in 2006 compared to $57.44 per barrel for oil and $7.76 per MCF for natural gas for the comparable period in 2005. During the 2006 nine month period production volumes on a barrel of oil equivalent basis increased to 4,017 compared to 3,613 in 2005.

During the third quarter of 2006 the Trust distributed $0.72 per unit to its Unitholders from funds flow of $0.86 per unit, an 84 percent payout ratio. This compares to $0.69 in the second quarter of 2006 and $0.60 in the third quarter of 2005.

Financial and Operational Discussion

Production

Average daily production volume for the nine months ended September 30, 2006 was 4,017 barrels of oil equivalent (BOE's) per day. BOE's are calculated using a conversion ratio of 6 MCF to 1 barrel of oil. The conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead and as such may be misleading if used in isolation. Production consists of 3,007 barrels per day of crude oil and natural gas liquids and 6,059 MCF per day of natural gas. Bonterra's first nine months of 2005 average production was 3,613 BOE's per day consisting of 2,679 barrels per day of crude oil and natural gas liquids and 5,601 MCF per day of natural gas.

The Trust drilled 27 gross (24 net) Cardium oil wells and 14 gross (12.2 net) shallow gas wells on its operated lands in the first nine months of 2006. In addition the Trust participated in the drilling of six gross (.9 net) Cardium oil wells on a non-operated property all of which were still behind pipe as of September 30, 2006. As at September 30, 2006 Bonterra had 18 gross (16.7 net) Cardium oil wells, 16 gross (13.7 net) natural gas wells and 7 gross (5.5 net) coal-bed wells drilled but not on production on its operated lands. During the first nine months of 2006, the Trust tied-in 22 gross (18.1 net) Cardium wells and one (one net) natural gas well on its operated lands.

Subsequent to September 30, 2006 and up to the date of this report, Bonterra has put on production eight gross (6.8 net) Cardium oil wells. Management anticipates that the majority of the remaining drilled but not producing Cardium wells will be completed and tied-in by the end of 2006. The Trust is currently completing and testing several of its Edmonton sand gas wells drilled in the current year. It is currently anticipated that the majority of the gas wells will be on production by the end of the first quarter of 2007. Bonterra is waiting on final regulatory decisions and recovery in natural gas pricing prior to commencing further completion work on the coal-bed methane wells.

Overall production rates in the third quarter of 2006 were affected by continued wet conditions resulting in the inability to perform maintenance on wells and tie-in newly drilled wells on a timely basis. Production in the Dodsland area of Saskatchewan averaged 223 BOE per day consistent with second quarter production however production is still approximately 60 BOE's per day lower from 2005 average production. The Trust is working in conjunction with the contract operator of this property to restore production to 2005 levels as soon as possible.

Revenue

Revenue from petroleum and natural gas sales was $67,015,000 (2005 – $54,085,000). The increase in revenue over the 2005 first nine months was primarily due to higher commodity prices and additional production from the wells drilled during the fall 2005 drill program. The average price received for crude oil and natural gas liquids during the first nine months of 2006 was $66.06 ($71.11 in the third quarter) per barrel and $7.54 ($6.95 in the third quarter) per MCF for natural gas compared to $57.44 per barrel and $7.66 per MCF in the corresponding 2005 period. On a quarter over quarter basis, revenue increased by $446,000 due to increased crude oil prices and the recording of a Q3 hedging gain of $396,000 verses a hedging loss of $180,000 in Q2 2006.

Although the Trust received higher U.S. WTI oil prices and U.S. Nymex natural gas prices in the first nine months of 2006 than in the corresponding 2005 period, the increases were partially offset by the rising Canadian dollar. The rising Canadian dollar negatively impacted the 2006 first nine months compared to the 2005 first nine months funds flow from operations by approximately 26 cents per unit and approximately 25 cents per unit on net earnings.

Gross revenue has been reduced by $695,000 (2005 – $3,019,000) due to lower prices received as a result of price hedging. The Trust will continue to assess hedging future production to assist in managing its funds flow. The Trust continues to follow the policy of protecting production that has high operating costs with hedges that provide a significant level of profitability and also to provide for a reasonable amount of funds flow protection for development projects. The Trust will however maintain a policy of not hedging more than 50 percent of production to allow it to benefit from any price movements in either crude oil or natural gas. Kindly refer to Note 7 to the attached interim financial statements for present hedging details. At September 30, 2006, the fair value of the outstanding commodity hedging contracts was a net asset of $1,872,000 (December 31, 2005 – $1,349,000 net liability).

Royalties

Royalties paid by the Trust consist primarily of Crown royalties paid to the Provinces of Alberta and Saskatchewan. During the first nine months of 2006 the Trust paid $6,546,000 (2005 – $4,557,000) in Crown royalties and $1,552,000 (2005 – $1,411,000) 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 (2005 – eight percent) and approximately two percent (2005 – two percent) for other royalties before hedging adjustments. The Trust is eligible for Alberta Crown Royalty rebates up to a maximum annual amount of $500,000 for Alberta production from all wells that it drilled on Crown lands and from a small number of purchased wells. The Government of Alberta recently announced that effective January 1, 2007 this rebate will be eliminated. It is estimated that funds flow will be reduced by $500,000 in 2007.

Gain on Sale of Property

During the first quarter of 2006, the Trust disposed of a non-operated; non-core property for gross proceeds of $750,000 (approximately $75,000 per producing BOE). The Trust follows successful efforts accounting for its oil and gas properties and therefore reported a gain of $532,000 on the difference between the depleted value of the property and the above proceeds. A similar disposal occurred in the second quarter of 2005 resulting in a gain of $263,000.

Production Costs

Production costs for the nine months ended September 30, 2006 were $16,241,000 compared to $14,662,000 for the nine months ended September 30, 2005. On a BOE basis production costs averaged $14.88 in 2006 verses $14.86 in the corresponding 2005 period. The 2005 production cost figure included approximately $700,000 ($0.71 per BOE) for one time items. After adjusting for these items the Trust recorded a year over year increase of approximately 5 percent in overall costs on a BOE basis. Q3 production costs increased $289,000 over Q2 due primarily to delays in Q2 well maintenance programs caused by spring breakup. This is typical of operations in Central Alberta as spring thaw makes roads and leases impassable for well service equipment.

The Trust's production comes primarily from low productivity wells. These wells generally result in higher production costs on a per unit-of-production basis as costs such as municipal taxes, surface lease, power and personnel costs are not variable with production volumes. Production costs in the $14 to $15 per BOE range are expected. The high production costs for the Trust are substantially offset by low royalty rates of approximately 12 percent, which is much lower than industry average for conventional production and on a combined basis results in high cash net backs despite higher than average production costs.

General and Administrative Expenses

General and administrative expenses were $1,814,000 ($570,000 in the third quarter) in the first nine months of 2006 compared to $1,870,000 in the nine months ended September 30, 2005 and $612,000 in the three months ended June 30, 2006.

Overhead costs on a BOE bases decreased to $1.65 per BOE in the first nine months of 2006 compared to $1.90 per BOE in the first nine months of 2005. The decrease in general and administrative expenses year over year was due primarily to increased cost recoveries from management fees and well administration charges. The quarter over quarter decrease of $42,000 was due primarily to annual trustee fees paid in the second quarter.

The Trust received a management fee from Comaplex Minerals Corp., a company with common directors and management, of $225,000 (2005 – $180,000) for management services, accounting services and office administration. In addition the Trust received a management fee from Pine Cliff Energy Ltd., a company with common directors and management, of $162,000 (2005 – $96,000) for management services, accounting services and office administration. These recoveries have been offset against the Trust's general and administrative expense.

Interest Expense

Interest expense increased to $1,068,000 ($414,000 in the third quarter) for the nine months ended September 30, 2006 compared to $436,000 for the nine months ended September 30, 2005. Increased average debt levels and increased interest rates were the primary factors in the increase in interest expense. Q3 2006 interest costs were marginally lower by $9,000 compared to Q2 2006. Although the Q3 period-end debt level was $6,183,000 higher than Q2, the average debt level during Q3 was about equal to Q2 due to the timing of payment of drilling costs. The Trusts average borrowing rate of 5.5 percent for the third quarter of 2006 was approximately the same as the rate for the second quarter. The Trust's total debt as a percentage of annualized third quarter funds flow was approximately eight months which is significantly less than the Trust's goal of one year.

The Trust's bank loan increased by approximately $17.5 million from December 31, 2005 compared to September 30, 2006. The increase is due to the payment of the balance of the costs in 2006 for the 2005 fourth quarter drilling program as well as for expenditures related to the Trusts 2006 drill program and a large number of wells drilled not being on production or just recently having been placed on production and therefore making no or little contribution to funds flow and would have been used to reduce debt. Offsetting the cost of capital expenditures was proceeds of $2,677,000 from the exercise of unit options and retained funds flow of approximately $6 million.

Unit Based Compensation

Unit 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. The Trust issued 407,000 unit options in May 2006 at an average price of $28.75. As a result of the issuances, the Trust recorded an increase in the third quarter of 2006 of $125,000 in unit based compensation over Q2 2006.

Depletion, Depreciation and Accretion

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

Provision for depletion, depreciation and accretion was $8,726,000 and $7,335,000 for the nine month periods ending September 30, 2006 and September 30, 2005 respectively. The increase was primarily due to increased production resulting from the Trust's 2005/2006 drill programs. The Trust continues to replace production declines with newly drilled wells that have higher capital costs resulting in approximately $300,000 of additional depletion costs in Q3 2006 verses Q2 2006. The Trust has capital costs of just over $6 per proven BOE of reserves based on the December 31, 2005 independent engineering report.

After conducing production tests in 2005, the Trust determined that some wells drilled in 2004 were not capable of economic production and therefore provided for $617,000 in dry hole costs. To date in 2006, none of the wells drilled have been determined by Trust engineers to be incapable of economic production and as such no provision has been recorded in 2006.

Income Taxes

Taxable income earned within the Trust is required to be allocated to its Unitholders and as such the Trust will not incur any current taxes. However, the Trust operates its oil and gas interests through its 100 percent owned subsidiaries Bonterra Energy Corp. (Bonterra Corp.), Comstate Resources Ltd. (Comstate) 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 resource surcharge rate from 3.6 percent to 3.3 effective July 1, 2006 with further reductions to 3 percent by 2008.

Future tax provision relates to the future taxes that exist within Bonterra Corp., Comstate, and Novitas. The liability on the balance sheet relates to temporary differences existing between Bonterra Corp.'s, Comstate's and Novitas' book value of their assets and their remaining tax pools.

Net Earnings

Net earnings increased to $30,779,000 in the first nine months of 2006 from $23,550,000 in the corresponding 2005 period. Revenue increases due to increased commodity prices and production volumes was the primary reason for the net earnings increase of $7,229,000 or 31 percent. The Trust's quarter over quarter net earnings remained relatively unchanged as both production volumes and commodity prices remained relatively unchanged.

Funds Flow from Operations

Funds flow from operations for the nine months ending September 30, 2006 was $40,562,000 ($14,401,000 in the third quarter) compared to $32,090,000 for the nine months ended September 30, 2005 and $14,008,000 for the three month period ending June 30, 2006. Funds flow from operations is not a recognized measure under GAAP. The Trust believes that in addition to net earnings, funds flow from operations is a useful supplemental measure as it demonstrates the Trust's ability to generate the cash necessary to make trust distributions, repay debt or fund future growth through capital investment. Investors are cautioned, however, that this measure should not be construed as an indication of the Trust's performance. The Trust's method of calculating this measure may differ from other issuers and accordingly, it may not be comparable to that used by other issuers. For these purposes, the Trust defines funds flow from operations as funds provided by operations before changes in non-cash operating working capital items excluding gain on sale of property.

The increase over the first nine months of 2005 was primarily due to higher commodity prices and increased production resulting from the Trust's 2005/2006 drill programs. As with all oil and gas producers the Trust's funds flow is highly dependent on commodity prices.

The following reconciliation compares funds flow for the first nine months of 2006 and 2005 to the Trust's cash flow from operations as calculated according to Canadian generally accepted accounting principles:

	2006	2005
Cash flow from operating activities	**$40,019,000**	$26,643,000
Items not affecting funds flow		
Gain on sale of property	**532,000**	263,000
Changes in accounts receivable	**(955,000)**	2,764,000
Changes in crude oil inventory	**186,000**	68,000
Changes in parts inventory	**(112,000)**	(167,000)
Changes in prepaid expenses	**604,000**	74,000
Changes in accounts payable and accrued liabilities	**(105,000)**	2,215,000
Asset retirement obligations settled	**393,000**	230,000
Funds flow for the period	**$40,562,000**	$32,090,000

Cash Netback

The following table illustrates the Trust's cash netback for the nine month periods ended:

$ per Barrel of Oil Equivalent (BOE)	**September 30 2006**	September 30 2005
Production volumes (BOE)	**1,096,723**	986,213
Gross production revenue	**$61.11**	$54.84
Royalties	**(6.94)**	(5.77)
Field operating	**(14.88)**	(14.86)
Field netback	**39.29**	34.21
General and administrative	**(1.65)**	(1.90)
Interest and taxes	**(1.23)**	(0.09)
Cash netback	**$36.41**	$32.22

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

$ per Barrel of Oil Equivalent (BOE)	**September 30 2006**	June 30 2006
Production volumes (BOE)	**369,104**	366,900
Gross production revenue	**$64.12**	$63.28
Royalties	**(6.77)**	(7.40)
Field operating	**(15.41)**	(14.72)
Field netback	**41.94**	41.16
General and administrative	**(1.55)**	(1.68)
Interest and taxes	**(1.38)**	(1.40)
Cash netback	**$39.01**	$38.08

Liquidity and Capital Resources

During the first nine months of 2006, the Trust incurred capital costs of $28,891,000 excluding proceeds on disposition of $750,000 for a non-core non-operated property. The Trust drilled 27 gross (24 net) Cardium oil wells and 14 gross (12.2 net) shallow gas wells in the first nine months of 2006 on its operated lands. In addition several wells on non-operated properties were drilled during the nine month period.

The Trust currently has plans to drill a total of 50 gross (43 net) Cardium infill oil and Edmonton sands shallow natural gas wells in 2006. Further infill drilling to enhance crude oil production is planned in several areas where the Trust has non-operated interests. On the non-operated prospects the Trust will participate with the operator. Total capital cost of approximately $35,000,000 is budgeted for 2006. The Trust has increased its drilling budget from that announced during the second quarter due to drilling of higher ownership wells as well as more Cardium infill wells and fewer natural gas wells. In addition, operators of two non-operated properties have commenced fall drill programs resulting in additional capital expenditure requirements by the Trust. The capital expenditures will be funded from funds flow, the Trust's lines of credit and funds from the exercising of employee unit options.

The Trust through its operating subsidiaries has a bank revolving credit facility of $49,900,000 at September 30, 2006 (December 31, 2005 – $36,900,000).

The Trust is authorized to issue an unlimited number of trust units without nominal or par value. Equity transactions during the past nine months are as follows:

Issued	Number	Amount
Trust Units		
Balance, January 1, 2006	16,535,158	$83,900,000
Issued pursuant to Trust's unit option plan	229,500	2,677,000
Transfer of contributed surplus to unit capital	–	165,000
Balance, September 30, 2006	16,764,658	$86,742,000

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,670,000 (December 31, 2005 – 1,635,000) 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 September 30, 2006 and December 31, 2005, and changes during the nine month and twelve month periods ending on those dates is presented below:

	September 30, 2006		December 31, 2005	
	Options	**Weighted-Average Exercise Price**	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	**646,000**	**$18.67**	565,000	$11.56
Options granted	**447,000**	**29.24**	407,000	23.32
Options exercised	**(229,500)**	**11.66**	(256,000)	11.03
Options cancelled	**(16,000)**	**23.35**	(70,000)	16.35
Outstanding at end of period	**847,500**	**$26.05**	646,000	$18.67
Options exercisable at end of period	**10,500**	**$20.72**	214,000	$10.89

The following table summarizes information about unit options outstanding at September 30, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 9/30/06	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 9/30/06	Weighted-Average Exercise Price
$10.00	2,000	0.4 years	$10.00	2,000	$10.00
$15.20-$15.60	38,000	0.5 years	15.22	–	–
$22.45-$23.35	360,500	2.5 years	23.33	8,500	23.24
$28.70-$28.75	407,000	3.3 years	28.75	–	–
$32.10-$33.80	40,000	3.3 years	33.55	–	–
$10.00-$33.80	847,500	2.8 years	$26.05	10,500	$20.72

Quarterly Financial Information

	2006			2005				2004
	3rd	2nd	1st	4th	3rd	2nd	1st	4th
Financial ($000, except $ per unit)								
Revenue – oil and gas	23,665	23,219	20,131	21,753	20,533	17,114	16,438	14,774
Net Earnings	10,441	10,617	9,721	9,918	9,309	7,115	7,126	6,389
Per Unit Basic	0.62	0.64	0.58	0.59	0.57	0.44	0.44	0.42
Per Unit Fully Diluted	0.62	0.63	0.58	0.59	0.56	0.43	0.43	0.41

OUTLOOK

Bonterra is confident that it will be able to continue its long term growth in production volumes and reserves by properly managing the development of its large inventory of drill locations. What is difficult to predict is the long term impact on trusts by the recently proposed federal government taxation for trusts. As previously advised, Bonterra does not have sufficient details from the government at the present time to determine the future impact of this taxation. When more information is provided to the trust industry management will attempt to provide further information.

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

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

Submitted on behalf of the Board of Directors,

George F. Fink

President, CEO and Director

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

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

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

CONSOLIDATED BALANCE SHEETS

As at September 30, 2006 (unaudited) and December 31, 2005

Financial ($)

	2006	2005
Assets		
Current		
Accounts receivable	10,407,000	11,020,000
Crude oil inventory	1,056,000	836,000
Parts inventory	109,000	221,000
Prepaid expenses	1,385,000	781,000
Investments in related party (Note 2)	461,000	461,000
	13,418,000	13,319,000
Property and Equipment (Note 3)		
Petroleum and natural gas properties and related equipment	168,136,000	139,798,000
Accumulated depletion and depreciation	(50,899,000)	(42,968,000)
Net Property and Equipment	117,237,000	96,830,000
	130,655,000	110,149,000
Liabilities		
Current		
Distribution payable	–	3,638,000
Accounts payable and accrued liabilities	14,569,000	11,476,000
Debt (Note 4)	37,702,000	20,177,000
	52,271,000	35,291,000
Future Income Tax Liability	4,701,000	4,341,000
Asset Retirement Obligations	13,296,000	13,195,000
	70,268,000	52,827,000
Unitholders' Equity		
Unit capital (Note 5)	86,742,000	83,900,000
Contributed surplus	1,167,000	636,000
Accumulated earnings	115,935,000	85,156,000
Accumulated cash distributions	(143,457,000)	(112,370,000)
	60,387,000	57,322,000
	130,655,000	110,149,000

CONSOLIDATED STATEMENTS OF UNITHOLDERS' EQUITY

For the Periods Ended September 30 (unaudited)
Financial ($)

	Three Months		Nine Months	
	2006	2005	**2006**	2005
Unitholders' equity, beginning of period	**61,202,000**	60,467,000	**57,322,000**	54,060,000
Net earnings for the period	**10,441,000**	9,309,000	**30,779,000**	23,550,000
Net capital contributions	**311,000**	210,000	**2,677,000**	1,520,000
Units issued on acquisition of Novitas Energy Ltd. (Note 6)	**–**	–	**–**	5,681,000
Unit issue costs on acquisition of Novitas Energy Ltd. (Note 6)	**–**	–	**–**	(259,000)
Unit option adjustment	**332,000**	182,000	**697,000**	353,000
Cash distributions	**(11,899,000)**	(9,506,000)	**(31,088,000)**	(24,243,000)
Unitholders' Equity, End of Period	**60,387,000**	60,662,000	**60,387,000**	60,662,000

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED EARNINGS

For the Periods Ended September 30 (unaudited)

Financial ($, except $ per unit)

	Three Months		Nine Months	
	2006	2005	**2006**	2005
Revenue				
Oil and gas sales	**23,665,000**	20,533,000	**67,015,000**	54,085,000
Royalties	**(2,647,000)**	(2,350,000)	**(8,098,000)**	(5,968,000)
Alberta royalty tax credits	**149,000**	118,000	**484,000**	277,000
Gain on sale of property (Note 3)	**–**	–	**532,000**	263,000
Interest and other	**4,000**	10,000	**39,000**	29,000
	21,171,000	18,311,000	**59,972,000**	48,686,000
Expenses				
Production costs	**5,689,000**	5,038,000	**16,241,000**	14,662,000
General and administrative	**570,000**	727,000	**1,814,000**	1,870,000
Interest on debt	**414,000**	148,000	**1,068,000**	436,000
Unit based compensation	**332,000**	182,000	**697,000**	353,000
Dry hole costs	**–**	617,000	**–**	617,000
Depletion, depreciation and accretion	**3,219,000**	2,507,000	**8,726,000**	7,335,000
	10,224,000	9,219,000	**28,546,000**	25,273,000
Earnings before Income Taxes	**10,947,000**	9,092,000	**31,426,000**	23,413,000
Income Taxes (Recovery)				
Current	**97,000**	189,000	**287,000**	(372,000)
Future	**409,000**	(406,000)	**360,000**	235,000
	506,000	(217,000)	**647,000**	(137,000)
Net Earnings for the Period	**10,441,000**	9,309,000	**30,779,000**	23,550,000
Accumulated earnings at beginning of period	**105,494,000**	65,929,000	**85,156,000**	51,688,000
Accumulated Earnings at End of Period	**115,935,000**	75,238,000	**115,935,000**	75,238,000
Net Earnings per Trust Unit – Basic	**0.62**	0.57	**1.84**	1.44
Net Earnings per Trust Unit – Diluted	**0.62**	0.56	**1.82**	1.42

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Periods Ended September 30 (unaudited)
Financial ($)

	Three Months		Nine Months	
	2006	2005	**2006**	2005
Operating Activities				
Net earnings for the period	**10,441,000**	9,309,000	**30,779,000**	23,550,000
Items not affecting cash				
Gain on sale of property	**–**	–	**(532,000)**	(263,000)
Unit based compensation	**332,000**	182,000	**697,000**	353,000
Depletion, depreciation and accretion	**3,219,000**	2,507,000	**8,726,000**	7,335,000
Dry hole costs	**–**	617,000	**–**	617,000
Future income taxes	**409,000**	(406,000)	**360,000**	235,000
	14,401,000	12,209,000	**40,030,000**	31,827,000
Change in non-cash operating working capital items				
Accounts receivable	**665,000**	(1,484,000)	**955,000**	(2,764,000)
Crude oil inventory	**(33,000)**	24,000	**(186,000)**	(68,000)
Parts inventory	**116,000**	(30,000)	**112,000**	167,000
Prepaid expenses	**(73,000)**	101,000	**(604,000)**	(74,000)
Accounts payable and accrued liabilities	**(710,000)**	(209,000)	**105,000**	(2,215,000)
Asset retirement obligations settled	**(268,000)**	6,000	**(393,000)**	(230,000)
	(303,000)	(1,592,000)	**(11,000)**	(5,184,000)
Cash Provided by Operating Activities	**14,098,000**	10,617,000	**40,019,000**	26,643,000
Financing Activities				
Increase (decrease) in debt	**6,183,000**	(9,000)	**17,525,000**	6,137,000
Unit option proceeds	**311,000**	210,000	**2,677,000**	1,520,000
Unit issue costs on acquisition of Novitas Energy Ltd.	**–**	–	**–**	(259,000)
Unit distributions	**(11,899,000)**	(9,506,000)	**(34,726,000)**	(26,933,000)
Cash Used in Financing Activities	**(5,405,000)**	(9,305,000)	**(14,524,000)**	(19,535,000)
Investing Activities				
Property and equipment expenditures	**(12,597,000)**	(3,130,000)	**(28,891,000)**	(6,572,000)
Proceeds on sale of properties	**–**	–	**750,000**	1,097,000
Partial refund of abandonment deposit	**–**	679,000	**–**	1,522,000
Cash portion of Novitas Energy Ltd. acquisition	**–**	–	**–**	(769,000)
Change in non-cash working capital items				
Accounts receivable	**379,000**	(224,000)	**(342,000)**	579,000
Accounts payable and accrued liabilities	**3,525,000**	1,363,000	**2,988,000**	(2,965,000)
Cash Used in Investing Activities	**(8,693,000)**	(1,312,000)	**(25,495,000)**	(7,108,000)
Net Cash Inflow	**–**	–	**–**	–
Cash, beginning of period	**–**	–	**–**	–
Cash, End of Period	**–**	–	**–**	–
Cash Interest Paid	**414,000**	148,000	**1,068,000**	436,000
Cash Taxes Paid (Recovered)	**102,000**	39,000	**(292,000)**	594,000

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS

Periods Ended September 30, 2006 and 2005 unaudited

1. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies and methods of application followed in the preparation of the interim financial statements are the same as those followed in the preparation of the Trust's 2005 annual financial statements. These interim financial statements do not include all disclosure required for annual financial statements. The interim financial statements as presented should be read in conjunction with the 2005 annual financial statements.

2. INVESTMENT IN RELATED PARTY

The investment consists of 689,682 (December 31, 2005 – 689,682) common shares in Comaplex Minerals Corp. (Comaplex), a company with common directors and management. The investment is recorded at cost. The fair market value as determined by using the trading price of the stock at September 30, 2006 was $2,069,000 (December 31, 2005 – $2,448,000). The common shares trade on the Toronto Stock Exchange under the symbol CMF. The investment represents less than a two percent ownership in the outstanding shares of Comaplex.

3. PROPERTY AND EQUIPMENT

	September 30, 2006		December 31, 2005	
	Cost	Accumulated Depletion and Depreciation	Cost	Accumulated Depletion and Depreciation
Undeveloped land	$ 334,000	$ –	$ 334,000	$ –
Petroleum and natural gas properties and related equipment	166,997,000	50,490,000	138,713,000	42,622,000
Furniture, equipment and other	805,000	409,000	751,000	346,000
	$ 168,136,000	$ 50,899,000	$ 139,798,000	$ 42,968,000

During the first quarter the Trust disposed of a non-core property for gross proceeds of $750,000.

4. DEBT

The Trust through its operating subsidiaries has a bank revolving credit facility of $49,900,000 at September 30, 2006 (December 31, 2005 – $36,900,000). The terms of the credit facilities provide that the loans are due on demand and are subject to annual review. The credit facilities have no fixed payment requirements. The amount available for borrowing under the credit facilities is reduced by the amount of outstanding letters of credit. Letters of credit totalling $340,000 were issued at September 30, 2006 (December 31, 2005 – $340,000). Collateral for the loans consists of a demand debenture providing a first floating charge over all of the Trust's subsidiaries assets, and a general security agreement.

The credit facilities carry an interest rate of Canadian chartered bank prime. The Trust has classified borrowing under its bank facilities as a current liability as required by guidance under the CICA's Emerging Issues Committee Abstract 122. It has been management's experience that these types of loans which are required to be classified as a current liability are seldom called by principal bankers as long as all the terms and conditions of the loan are complied with. Cash interest paid during the nine month periods ended September 30, 2006 and 2005 for these loans were $1,068,000 and $436,000 respectively.

5. UNIT CAPITAL

Authorized

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

Issued	Number	Amount
Trust Units		
Balance, January 1, 2006	16,535,158	$83,900,000
Issued pursuant to Trust's unit option plan	229,500	2,677,000
Transfer of contributed surplus to unit capital	–	165,000
Balance, September 30, 2006	16,764,658	$86,742,000

The Trust provides an option plan for its directors, officers, employees and consultants. Under the plan, the Trust may grant options for up to 1,670,000 (December 31, 2005 – 1,635,000) 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 September 30, 2006 and December 31, 2005, and changes during the nine month and twelve month periods ending on those dates is presented below:

	September 30, 2006		December 31, 2005	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Outstanding at beginning of period	646,000	$18.67	565,000	$11.56
Options granted	447,000	29.24	407,000	23.32
Options exercised	(229,500)	11.66	(256,000)	11.03
Options cancelled	(16,000)	23.35	(70,000)	16.35
Outstanding at end of period	847,500	$26.05	646,000	$18.67
Options exercisable at end of period	10,500	$20.72	214,000	$10.89

The following table summarizes information about unit options outstanding at September 30, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding At 9/30/06	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable At 9/30/06	Weighted-Average Exercise Price
$10.00	2,000	0.4 years	$10.00	2,000	$10.00
$15.20-$15.60	38,000	0.5 years	15.22	–	–
$22.45-$23.35	360,500	2.5 years	23.33	8,500	23.24
$28.70-$28.75	407,000	3.3 years	28.75	–	–
$32.10-$33.80	40,000	3.3 years	33.55	–	–
$10.00-$33.80	847,500	2.8 years	$26.05	10,500	$20.72

The Trust records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants.

6. RELATED PARTY TRANSACTIONS

The Trust received a management fee from Comaplex of $225,000 (2005 – $180,000) for management services, accounting services and office administration. This cost has been included as a recovery in general and administrative expenses. The above charge represents the fair value of the services rendered. At September 30, 2006 the Trust had an accounts receivable from Comaplex of $43,000 (December 31, 2005 – $29,000).

The Trust received a management fee from Pine Cliff Energy Ltd. (Pine Cliff) of $162,000 (2005 – $96,000) for management services, accounting services and office administration. This fee has been included as a recovery in general and administrative expenses. As at September 30, 2006 the Trust had no amounts for accounts receivable from or accounts payable to Pine Cliff. The above charge represents the fair value of the services rendered.

7. COMMITMENTS – FUTURE SALES AGREEMENTS

The Trust entered into the following commodity hedging contracts for a portion of its 2006 and 2007 production:

Period of Agreement	Commodity	Volume per day	Index	Price (Cdn.)
October 1, 2006 to December 31, 2006	Crude Oil	500 barrels	WTI	Floor of $70 and ceiling of $80.10 per barrel
July 1, 2006 to December 31, 2006	Crude Oil	500 barrels	WTI	Floor of $74.22 and ceiling of $85 per barrel
January 1, 2007 to June 30, 2007	Crude Oil	500 barrels	WTI	Floor of $74.55 and ceiling of $85 per barrel
January 1, 2007 to June 30, 2007	Crude Oil	500 barrels	WTI	Floor of $75 and ceiling of $95.47 per barrel
July 1, 2007 to December 31, 2007	Crude Oil	500 barrels	WTI	Floor of $75 and ceiling of $93 per barrel
April 1, 2006 to October 31, 2006	Natural Gas	2,000 GJ's	AECO	Floor of $8.55 and ceiling of $14 per GJ
November 1, 2006 to March 31, 2007	Natural Gas	2,000 GJ's	AECO	Floor of $6.65 and ceiling of $12.50 per GJ
December 1, 2006 to March 31, 2007	Natural Gas	1,500 GJ's	AECO	Floor of $6.00 and ceiling of $9.65 per GJ
April 1, 2007 to July 31, 2007	Natural Gas	2,000 GJ's	AECO	$6.52 per GJ
*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

*Entered into subsequent to September 30, 2006.

During the nine month period ended September 30, 2006, the Trust recorded a reduction to revenue of $695,000 (September 30, 2005 – $3,019,000) from its hedging contracts. As at September 30, 2006 the fair value of the outstanding commodity hedging contracts was a net asset of $1,872,000 (December 31, 2005 – $1,349,000 net liability).

8. SUBSEQUENT EVENT – DISTRIBUTIONS

Subsequent to September 30, 2006, the Trust declared a distribution of $0.24 per unit payable on October 31, 2006 to Unitholders of record on October 16, 2006. The distribution represents funds flow in the Trust for the month of September 2006.

On November 2, the Trust declared a distribution of $0.24 per unit payable on November 30, 2006 to Unitholders of record on November 15, 2006. The distribution represents funds flow in the Trust for the month of October 2006.

Bonterra
Energy Income Trust

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