BONAVISTA ENERGY TRUST

Annual Report 2007

Highlights

	Three Months ended December 31,		Years ended December 31,	
	2007	2006	2007	2006
Financial				
($ thousands, except per unit)				
Production revenues	242,361	220,484	911,346	910,079
Funds from operations (1)	127,778	121,305	502,783	496,438
Per unit (1) (2)	1.20	1.17	4.76	4.86
Distributions declared	77,136	76,296	307,401	324,016
Per unit	0.90	0.90	3.60	3.87
Percentage of funds from operations (1)	60%	63%	61%	65%
Net income	63,631	67,635	218,187	301,270
Per unit (2)	0.60	0.65	2.07	2.95
Total assets			2,242,057	2,067,931
Long-term debt, including working capital deficiency			723,003	518,448
Unitholders' equity			1,060,967	1,130,253
Capital expenditures:				
Exploitation and development	58,440	58,744	267,660	280,563
Acquisitions, net	(425)	(345)	98,696	35,790
Weighted average outstanding equivalent trust units: (thousands) (2)				
Basic	106,762	103,533	105,543	102,156
Diluted	109,102	106,304	108,075	105,615
Operating				
(boe conversion – 6:1 basis)				
Production:				
Natural gas (mmcf/day)	170	174	171	177
Oil and liquids (bbls/day)	24,775	24,114	24,034	23,068
Total oil equivalent (boe/day)	53,029	53,106	52,505	52,593
Product prices: (3)				
Natural gas ($/mcf)	6.74	7.44	6.95	7.38
Oil and liquids ($/bbl)	58.04	46.52	54.40	50.42
Operating expenses ($/boe)	8.58	8.18	8.47	7.92
General and administrative expenses ($/boe)	0.74	0.72	0.70	0.58
Cash costs ($/boe) (4)	11.56	10.47	11.01	9.92
Operating netback ($/boe) (5)	29.17	27.12	28.77	27.85

Highlights (cont'd)	December 31, 2007	2006
Drilling (gross wells)	216	325
Natural gas	108	220
Oil	97	86
Average success rate	95%	94%
Reserves:		
Proved:		
Natural gas (bcf)	427.1	428.2
Oil and liquids (mbbls)	63,724	63,643
Total oil equivalent (mboe)	134,911	135,006
Proved and probable:		
Natural gas (bcf)	561.0	542.9
Oil and liquids (mbbls)	85,955	83,615
Total oil equivalent (mboe)	179,454	174,091
% Proved producing	62%	62%
% Proved	75%	78%
% Probable	25%	22%
Net present value of future cash flow before income taxes ($ millions):		
0% discount rate	6,116	5,449
5% discount rate	4,116	3,612
10% discount rate	3,154	2,749
Reserve life index (years):		
Proved	7.3	7.3
Proved and probable	9.2	8.9
Finding, development and acquisition costs – proved and probable ($/boe):		
Including changes in future development expenditures	15.91	15.29
Excluding changes in future development expenditures	14.94	13.06
Recycle ratio – proved and probable: (5)		
Including changes in future development expenditures	1.8	1.8
Excluding changes in future development expenditures	1.9	2.1

Trust Unit Trading Statistics	Three Months ended December 31, 2007	September 30, 2007	June 30, 2007	March 31, 2007
($ per unit, except volume)				
High	31.85	31.38	33.54	31.89
Low	24.14	27.25	29.12	25.90
Close	28.50	29.02	30.60	30.85
Average Daily Volume	275,892	177,752	216,676	230,630

NOTES:

(1) Management uses funds from operations to analyze operating performance, distribution coverage and leverage. Funds from operations as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculations of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures. Funds from operations per unit is calculated based on the weighted average number of units outstanding consistent with the calculation of net income per unit.

(2) Basic per unit calculations include exchangeable shares which are convertible into trust units on certain terms and conditions.

(3) Product prices include realized gains or losses on financial instruments.

(4) Cash costs equal the total of operating, general and administrative, and financing expenses.

(5) Operating netback equals production revenues including realized gains or losses on financial instruments, less royalties, transportation and operating expenses, calculated on a boe basis. Operating netback is used in the recycle ratio calculation.

MESSAGE TO UNITHOLDERS

Bonavista Energy Trust ("Bonavista" or the "Trust") is pleased to report to its unitholders (the "Unitholders") its consolidated financial and operating results for the year ended December 31, 2007. The results for the fourth quarter of 2007 represents eighteen consecutive quarters of profitability for Bonavista since commencing operations as an energy trust in July 2003. The continued successful execution of Bonavista's proven strategies in the fourth quarter of 2007 are a testament to the validity and effectiveness of an operationally and technically focused energy trust. The fourth quarter and annual results for 2007 are also highlighted by an active and successful drilling and acquisitions program, which has led to attractive reserve addition costs. These costs have also benefited from somewhat lower service costs with the slowdown in industry activity in the latter half of 2007. This current environment creates the opportunity for Bonavista to continue to differentiate itself by posting solid financial results in an ever-changing economic landscape.

Other significant accomplishments for Bonavista in 2007 include:

- Operationally, production volumes held steady at 52,505 boe per day during 2007 versus 52,593 boe per day in 2006 and have increased 52% from 34,600 boe per day since commencement as an energy trust on July 2, 2003. Bonavista's current production rate is approximately 55,500 boe per day;
- Added 24.5 mmboe of proved and probable reserves during 2007, which replaced annual production by 1.3 times and also improved the Trust's proved and probable reserve life index to 9.2 years from 8.9 years in 2006. These reserves were added at an attractive finding, development and acquisition cost, including changes in future development expenditures, of $19.77 per boe on a proved basis ($19.21 per boe excluding changes in future development expenditures) and $15.91 per boe on a proved and probable basis ($14.94 per boe excluding changes in future development expenditures). A strong proved and probable recycle ratio of 1.8:1 (1.5:1 proved) was achieved in 2007 as a result of the low level of finding, development and acquisition costs. Overall in 2007, Bonavista increased proved and probable reserves by 3% to 179.5 mmboe while spending 73% of funds from operations on exploitation, development and acquisition expenditures;
- Maintained an active capital program during 2007, investing $267.7 million in exploitation and development activities. Bonavista drilled 216 wells with an overall 95% success rate, and we spent $98.7 million on 10 synergistic acquisitions within our core regions;
- Completed a strategic property acquisition in the Willesden Green area which complimented our existing assets with a high working interest ownership and operatorship of facilities and infrastructure. On January 14, 2008 we completed an additional acquisition of producing and undeveloped oil and natural gas properties to further complement our operations in this area as part of our 2008 capital program. We have assembled a new core property over the past two years, currently producing over 5,000 boe per day;
- Continued to actively participate at crown land sales, investing $33.2 million in land activity during the year compared to $20.6 million in 2006, and further enhancing our future drilling prospect inventory to more than three years;
- Invested $18.0 million to acquire 49 sections of undeveloped land through Crown and Freehold purchases in the light oil Bakken trend in the greater Viewfield area of southeast Saskatchewan. We have currently drilled five wells on these lands with promising results to date;
- Generated funds from operations of $502.8 million ($4.76 per unit) in 2007 and recorded strong profitability with net income of $218.2 million ($2.07 per unit). This resulted in an attractive average return on equity of 20% and a strong net income to funds from operations ratio of 43%;
- Established a new $1.0 billion credit facility with a syndicate of chartered banks. This facility is unsecured covenant-based, which significantly enhances Bonavista's financial flexibility to take advantage of future investment opportunities in 2008 and beyond; and
- Delivered top decile total returns, within the energy trust industry, to our Unitholders in 2007 and currently have a cash on cash yield of 12%. In addition, Bonavista has delivered cumulative distributions of $1.2 billion or $15.51 per trust unit since inception of our Trust in July 2003.

On October 25, 2007, the Government of Alberta announced its proposal for a new royalty framework in Alberta. The proposed changes to the Alberta Crown Royalty framework are to take effect on January 1, 2009. Bonavista will continue to analyze the information that becomes available with respect to the new crown royalty framework. Based upon initial documentation, royalty rates will increase substantially on medium depth natural gas, high productivity natural gas and light oil production in Alberta and as a result the economics of these opportunities have been negatively impacted under a higher price commodity scenario. The Government of Alberta is currently monitoring this negative impact and have indicated that, should their original decision result in unintended consequences, the framework could be reviewed and adjusted as required to re-stimulate activity. Bonavista will continue to assess the impact that the new royalty framework will have on our existing operations, including our capital allocations for 2008 and beyond. Bonavista has a strong history of remaining flexible and ensuring that it allocates capital to those projects delivering the highest rate of return and will continue to do so under this new royalty regime.

Strengths of Bonavista Energy Trust

Since restructuring into an energy trust in July 2003, Bonavista has maintained a high level of investment activity on its asset base, growing production by over 50% since that time. This activity stems from the operational and technical focus of our Trust and the ability to uncover value from our assets within the Western Canadian Sedimentary Basin. Our experienced and consistent technical teams have a solid understanding of our asset base and possess the necessary discipline and commitment to deliver profitable results to our Unitholders for the long-term. We actively participate in undeveloped land acquisitions through Crown land sales, property purchases or farm-in opportunities, which have all continued to add to our already extensive low-risk drilling inventory. This has led to low cost reserve additions, lengthening of our reserve life index, and a growing production base. Our production base is balanced 54% in favour of natural gas and 46% towards oil and liquids and is geographically focused within select medium depth, multi-zone regions in Alberta, Saskatchewan and British Columbia. This base has one of the lowest operating cost structures in the oil and natural gas trust sector. In addition, these high working interest assets are predominantly operated by Bonavista, ensuring that operating and capital cost efficiencies are maintained and that Bonavista controls the pace of its operations. All of these attributes combined, result in attractive operating netbacks for Bonavista.

Our team brings a successful track record of executing low to medium risk development programs, including both asset and corporate acquisitions, along with sound financial management. Unitholders benefit from a fully internalized, industry leading cost structure, which results in one of the lowest per unit overhead costs in the energy trust industry. The management team, along with a strong Board of Directors, possesses extensive experience in oil and natural gas operations, corporate governance and financial management. Directors, management and employees also own approximately 18% of the Trust, resulting in an alignment of interests with all Unitholders.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations should be read in conjunction with Bonavista Energy Trust's ("Bonavista" or the "Trust") audited consolidated financial statements and MD&A for the year ended December 31, 2007. The following MD&A of the financial condition and results of operations was prepared at, and is dated March 12, 2008. Our audited consolidated financial statements, Annual Report, and other disclosure documents for 2007 will be available on or before March 30, 2008 through our filings on SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

Basis of Presentation *- The financial data presented below has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar. For the purpose of calculating unit costs, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. A boe may be misleading, particularly if used in isolation. A boe conversion of 6 Mcf to one barrel is based on an energy equivalent conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

Forward-Looking Statements *– Certain information set forth in this document, including management's assessment of Bonavista's 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 Bonavista's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, changes in environmental, tax and royalty legislation, 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. Bonavista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements or if any of them do so, what benefits that Bonavista will derive therefrom. Bonavista disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law. Investors are also cautioned that cash-on-cash yield represents a blend of return of investor's initial investment and a return on investors initial investment and is not comparable to traditional yield on debt instruments where investors are entitled to full return of the principal amount of debt on maturity in addition to a return on investment through interest payments.*

Non-GAAP Measurements *- Within Management's discussion and analysis, references are made to terms commonly used in the oil and natural gas industry. Management uses "funds from operations" and the "ratio of debt to funds from operations" to analyze operating performance and leverage. Funds from operations as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net income or other measures of financial performance calculated in accordance with Canadian GAAP. All references to funds from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital and abandonment expenditures. Funds from operations per unit is calculated based on the weighted average number of trust units outstanding consistent with the calculation of net income per unit. Operating netbacks equal production revenue and realized gains or losses on financial instruments, less royalties, transportation and operating expenses calculated on a boe basis. Total boe is calculated by multiplying the daily production by the number of days in the period. Management uses these terms to analyze operating performance and leverage.*

Operations - Bonavista's exploitation and development program for the year ended December 31, 2007 led to the drilling of 216 wells in our four core regions with an overall success rate of 95%. This program resulted in 108 natural gas wells, 97 oil wells and 11 dry holes. Bonavista continues to emphasize deeper, higher impact drilling opportunities within the Northeast British Columbia and South Central Alberta core regions where we have experienced excellent success and attractive finding and development costs over this period. These activities have also lengthened our reserve life index and the predictability in our overall production base. We drilled 43 heavy oil targets in the Lloydminster area in 2007 resulting in 100% success and relatively stable heavy oil production of 7,500 bbls per day. In addition to the exploitation and development program, Bonavista executed 10 complementary acquisitions in its core regions during 2007.

Reserves – Reserve estimates have been calculated in compliance with the National Instrument 51-101 Standards of Disclosure ("NI 51-101"). Under NI 51-101, proved reserves are defined as reserves that can be estimated with a high degree of certainty to be recoverable with a target of a 90% probability that the actual reserves recovered over time will equal or exceed proved reserve estimates, while probable reserves are defined as having an equal (50%) probability that the actual reserves recovered will equal or exceed the proved and probable reserve estimates. In accordance with NI 51-101, proved undeveloped reserves have been recognized in cases where plans are in place to bring the reserves on production within a short, well defined time frame. Proved undeveloped reserves often involve infill drilling into existing pools. Of the Trust's net present value reserves, 81% were evaluated by independent third party engineers, GLJ Petroleum Consultants Ltd. ("GLJ") and Ryder Scott Company Canada in their reports dated February 26th, 2008 and March 4th, 2008 respectively, depending on the location of the property. The balance of approximately 19% of proved and probable reserves was evaluated internally. The reserve estimates contained in the following tables represent Bonavista's interest reserves before the deduction of royalties:

				Net Present Value @		
	Natural Gas	**Oil and Liquids**	**Total Reserves**	**0%**	**5%**	**10%**
	(bcf)	(mbbls)	(mboe)		(millions)	
Proved:						
Proved producing	373.0	49,729	111,887	$ 3,704	$ 2,713	$ 2,187
Proved non-producing	27.3	5,745	10,302	262	201	161
Proved undeveloped	26.8	8,249	12,722	492	297	203
Total proved (1)	427.1	63,724	134,911	4,457	3,211	2,551
Probable	133.9	22,231	44,543	1,659	906	603
Total proved and probable (1)	**561.0**	**85,955**	**179,454**	**$ 6,116**	**$ 4,116**	**$ 3,154**

	Natural Gas	**Oil and Liquids**	**Total Reserves**
	(bcf)	(mbbls)	(mboe)
Proved:			
December 31, 2006	428.2	63,643	135,006
Exploitation and development	35.2	6,279	12,139
Revisions (2)	2.9	(509)	(28)
Acquisitions, net	23.2	3,085	6,959
Production	(62.4)	(8,773)	(19,165)
December 31, 2007 (1)	**427.1**	**63,724**	**134,911**
Proved and probable:			
December 31, 2006	542.9	83,615	174,091
Exploitation and development	45.7	8,637	16,260
Revisions (2)	7.1	(1,212)	(32)
Acquisitions, net	27.7	3,688	8,300
Production	(62.4)	(8,773)	(19,165)
December 31, 2007 (1)	**561.0**	**85,955**	**179,454**

(1) Numbers may not add due to rounding.
(2) Revisions include economic factors.

Bonavista's 2007 year-end proved reserves totalled 134.9 mmboe, essentially unchanged compared to the 135.0 mmboe at the year-end of 2006. Bonavista's proved and probable reserves increased by 3% to 179.5 mmboe when compared to the 174.1 mmboe at year-end 2006. Bonavista's proved and probable reserve life index ("RLI") also increased during the year to 9.2 years, with the proved RLI at 7.3 years. Finding, development and acquisition costs in 2007, including changes in future capital expenditures, amounted to $19.77 per boe ($19.21 per boe before changes in future capital expenditures) on a proved basis and $15.91 per boe ($14.94 per boe before changes in future capital expenditures) on a proved and probable basis. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during the year in estimated future development costs generally will not reflect total finding and development costs relating to reserve additions for that year. Bonavista generated attractive recycle ratios of 1.8:1 for proved and probable reserves and 1.5:1 for proved reserves, including revisions and changes in future development expenditures; excluding changes in future development expenditures, the proved and probable recycle ratio increased to 1.9:1 and the proved recycle ratio remains unchanged at 1.5:1. Additional reserves disclosure tables, as required under NI 51-101, are contained in Bonavista's Annual Information Form that will be filed on SEDAR.

On October 25, 2007, the Government of Alberta announced its proposal for a New Royalty Framework ("NRF") in Alberta. The NRF is anticipated to take effect January 1, 2009, this will result in the Trust's royalty rates for the low value sensitivity case to increase by less than one percent. The net present value of the Trust's total reserves will decrease by less than two percent using GLJ's forecasted prices as at January 1, 2008 and a 10% discount rate.

Financial and operating highlights – The following is a summary of key financial and operating results for the respective periods noted:

	Three Months ended December 31,		Years ended December 31,	
	2007	**2006**	**2007**	**2006**
($ thousands, except per boe/Trust Unit Amounts and where noted)				
Product prices:				
Natural gas ($/mcf)	6.74	7.44	6.95	7.38
Oil and liquids ($/bbl)	58.04	46.52	54.40	50.42
Production:				
Natural gas (mmcf/d)	170	174	171	177
Oil and liquids (bbls/d)	24,775	24,114	24,034	23,068
Total production (boe/d)	53,029	53,106	52,505	52,593
Production revenues	242,361	220,484	911,346	910,079
per boe	49.68	45.13	47.55	47.41
Royalties	42,809	38,985	155,586	174,903
per boe	8.77	7.98	8.12	9.11
% of Production revenues	17.7%	17.7%	17.1%	19.2%
Operating expenses	41,867	39,945	162,371	152,087
per boe	8.58	8.18	8.47	7.92
Transportation expenses	10,364	10,874	41,397	40,065
per boe	2.12	2.23	2.16	2.09
General and administrative expenses	3,620	3,532	13,335	11,229
per boe	0.74	0.72	0.70	0.58
Financing expenses	10,915	7,684	35,209	26,960
per boe	2.24	1.57	1.84	1.40
Funds from operations	127,778	121,305	502,783	496,438
per boe	26.19	24.83	26.24	25.86
per unit – basic	1.20	1.17	4.76	4.86
Unit-based compensation	2,809	714	7,351	4,890
per boe	0.58	0.15	0.38	0.25
Depreciation, depletion and accretion	60,467	56,179	231,945	214,698
per boe	12.39	11.50	12.10	11.18
Income taxes (reduction)	(30,831)	(3,424)	(535)	(25,215)
per boe	(6.32)	(0.70)	(0.03)	(1.31)
Net income	63,631	67,635	218,187	301,270
per boe	13.04	13.84	11.39	15.69
per unit – basic	0.60	0.65	2.07	2.95
Distributions declared	77,136	76,296	307,401	324,016
per unit	0.90	0.90	3.60	3.87

Production - Overall for 2007 production was 52,505 boe per day, largely unchanged when compared to 52,593 boe per day for the same period a year ago. More specifically, average natural gas production decreased 3% to 171 mmcf per day in 2007 from 177 mmcf per day for the same period a year ago, while total oil and liquids production increased 4% to 24,034 bbls per day (comprised of 16,486 bbls per day of light and medium oil and 7,548 bbls per day of heavy oil) from 23,068 bbls per day (comprised of 16,007 bbls per day of light and medium oil and 7,061 bbls per day of heavy oil) for the same period in 2006. This trend was the result of a decision made earlier in 2007 to emphasize crude oil projects over natural gas projects due to the favorable oil economics. For the fourth quarter of 2007, production was also essentially unchanged at 53,029 boe per day when compared to 53,106 boe per day for the same period in 2006. Natural gas production decreased 2% to 170 mmcf per day in the fourth quarter of 2007 from 174 mmcf per day for the same period a year ago, while total oil and liquids production increased 3% to 24,775 bbls per day in the fourth quarter of 2007 (comprised of 16,825 bbls per day of light and medium oil and 7,950 bbls per day of heavy oil) from 24,114 bbls per day (comprised of 16,559 bbls per day of light and medium oil and 7,555 bbls per day of heavy oil) for the same period a year ago. Our current production is approximately 55,500 boe per day consisting of 54% natural gas, 33% light and medium oil and 13% heavy oil. Bonavista's diversified commodity investment approach minimizes our dependence on any one product.

Revenues - Revenues, excluding gains and losses on financial instruments, for the year ended December 31, 2007 increased slightly to $911.3 million when compared to $910.1 million for the same period a year ago. For the year ended December 31, 2007, our natural gas price including realized gains on financial instruments averaged $6.95 per mcf, a decrease of 6% from $7.38 per mcf for the same period in 2006. The average oil and liquids price increased 8% to $54.40 per bbl (comprised of $58.61 per bbl for light and medium oil and $45.20 per bbl for heavy oil) for the year ended December 31, 2007 from $50.42 per bbl (comprised of $53.94 per bbl for light and medium oil and $42.45 per bbl for heavy oil) for the same period in 2006. Revenues, excluding gains and losses on financial instruments, for the fourth quarter of 2007 increased by 10% to $242.4 million when compared to $220.5 million in the fourth quarter of 2006 due to higher average commodity prices. In the fourth quarter of 2007, natural gas prices averaged $6.74 per mcf, down 9% from $7.44 per mcf for the same period in 2006. The average oil and liquids price increased 25% to $58.04 per bbl (comprised of $62.32 per bbl for light and medium oil and $48.99 per bbl for heavy oil) in the fourth quarter of 2007 from $46.52 per bbl (comprised of $49.37 per bbl for light and medium oil and $40.28 per bbl for heavy oil) for the same period in 2006.

Commodity price risk management - As part of our financial management strategy, Bonavista has adopted a disciplined commodity price risk management program. The purpose of this program is to stabilize funds from operations against unpredictable commodity prices and protect acquisition economics. Bonavista’s Board of Directors has approved a commodity price risk management limit of 60% of forecast production, net of royalties, primarily using costless collars. Our strategy of using costless collars limits Bonavista’s exposure to downturns in commodity prices, while allowing for participation in commodity price increases.

Prior to January 1, 2007, Bonavista accounted for all of our financial contracts as hedges and included realized gains or losses in revenues. On January 1, 2007, with the adoption of new accounting standards for financial instruments and hedging, Bonavista discontinued hedge accounting treatment for our financial commodity derivative contracts. Accordingly, realized and unrealized gains on these financial instruments are recognized in the current period. See note 3 of the audited consolidated financial statements for the year ended December 31, 2007.

For the year ended December 31, 2007, our risk management program on financial instruments resulted in a net loss of $45.7 million, consisting of a realized loss of $665,000 and an unrealized loss of $45.1 million. The realized loss of $665,000 consisted of a $5.2 million gain on natural gas commodity derivative contracts and a $5.9 million loss on crude oil commodity derivative contracts. For the three months ended December 31, 2007, our risk management program on financial instruments resulted in a net loss of $36.5 million, consisting of a realized loss of $5.0 million and an unrealized loss of $31.5 million. The realized loss of $5.0 million consisted of a $1.7 million gain on natural gas commodity derivative contracts and a $6.7 million loss on crude oil commodity derivative contracts.

The following is a summary of commodity price risk management contracts as at December 31, 2007.

i) Financial instruments:

The Trust has hedged by way of costless collars to sell natural gas (gjs/d) and crude oil (bbls/d) as follows:

Volume	Average Price	Term
5,000 gjs/d	CDN$ 7.50 - CDN$ 10.55 – AECO	January 1, 2008 – March 31, 2008
5,000 gjs/d	CDN$ 7.00 - CDN$ 9.00 – AECO	April 1, 2008 – October 31, 2008
7,000 bbls/d	US$ 65.43 - US$ 78.58 – WTI	January 1, 2008 – December 31, 2008
1,000 bbls/d	CDN$ 49.00 - CDN$ 57.00 – Bow River	January 1, 2008 – December 31, 2008
2,000 bbls/d	US$ 65.00 - US$ 80.50 – WTI	January 1, 2009 – March 31, 2009

As at December 31, 2007, the market deficit of these derivative financial instruments was approximately $45.1 million.

ii) Physical purchase contracts:

The Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume	Average Price (CDN$ - AECO)	Term
20,000 gjs/d	$ 7.75 - $ 10.53	January 1, 2008 – March 31, 2008

Subsequent to December 31, 2007, the Trust has entered into the following commodity contracts:

i) Financial instruments:

The Trust has hedged by way of costless collars to sell natural gas (gjs/d) and crude oil (bbls/d) as follows:

Volume	Average Price	Term
20,000 gjs/d	CDN$ 7.38 - CDN$ 8.46 – AECO	April 1, 2008 – October 31, 2008
2,000 bbls/d	CDN$ 61.00 - CDN$ 71.75 – Bow River	April 1, 2008 – December 31, 2008
1,000 bbls/d	US$ 85.00 - US$ 105.60 – WTI	January 1, 2009 – December 31, 2009

ii) Physical purchase contracts:

The Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume	Average Price (CDN$ - AECO)	Term
45,000 gjs/d	$ 7.19 - $ 8.36	April 1, 2008 – October 31, 2008
25,000 gjs/d	$ 7.65 - $ 9.65	November 1, 2008 – March 31, 2009

Royalties - For the year ended December 31, 2007, royalties decreased 11% to $155.6 million from $174.9 million for the same period a year ago, primarily due to lower natural gas prices and favourable crown royalty adjustments relating to prior periods. In addition, royalties as a percentage of revenue including realized gains and losses on financial instruments decreased to 17.1% from 19.4% in 2006 primarily due to similar reasons. For the year ended December 31, 2007, royalties by product, as a percentage of revenue including realized gains and losses on financial instruments were 17.6% for natural gas, 16.8% for light and medium oil and 16.0% for heavy oil. For the year ended December 31, 2006, royalties by product, as a percentage of revenue including realized gains and losses on financial instruments were 21.1% for natural gas, 18.6% for light and medium oil and 14.1% for heavy oil. For the three months ended December 31, 2007, royalties increased 10% to $42.8 million from $39.0 million for the same period a year ago, largely attributed to increased heavy oil royalties resulting from the payout of two oil sand royalty projects. In addition, royalties as a percentage of revenue including realized gains and losses on financial instruments for the fourth quarter of 2007 also increased from 17.5% in 2006 to 18.0% in 2007 for similar reasons discussed above. For the three months ended December 31, 2007, royalties by product as a percentage of revenues including realized gains and losses on financial instruments were 18.1% for natural gas, 17.8% for light and medium oil and 18.4% for heavy oil. For the three months ended December 31, 2006, royalties by product, as a percentage of revenue including realized gains and losses on financial instruments were 18.9% for natural gas, 17.3% for light and medium oil and 12.4% for heavy oil.

Operating expenses - Operating expenses for the year ended December 31, 2007 increased 7% to $162.4 million compared to $152.1 million for the same period a year ago. Operating expenses for the fourth quarter of 2007 increased 5% to $41.9 million compared to $39.9 million for the same period a year ago. Over the past several months, operating costs have shown signs of stabilizing as we have experienced a slow-down in industry activity due to lower natural gas prices and the proposed changes to the Alberta Royalty framework. Average per unit operating costs for the year ended December 31, 2007 increased to $8.47 per boe which is up 7% from $7.92 per boe in the comparable period of 2006. For 2007, per unit operating expenses by product were $1.17 per mcf for natural gas, $9.16 per bbl for light and medium oil and $12.36 per bbl for heavy oil compared to $1.12 per mcf for natural gas, $8.73 per bbl for light and medium oil and $10.95 per bbl for heavy oil for 2006. For the three months ended December 31, 2007, operating costs increased 5% to $8.58 per boe from $8.18 per boe in the comparable period of 2006. Operating costs by product for the fourth quarter of 2007 were $1.16 per mcf for natural gas, $9.31 per bbl for light and medium oil and $12.72 per bbl for heavy oil compared to $1.13 per mcf for natural gas, $8.85 per bbl for light and medium oil and $11.70 per bbl for heavy oil. Notwithstanding the year over year increases, Bonavista continues to place significant emphasis on the control of operating costs and is continuing to pursue cost reduction initiatives.

Transportation expenses - Transportation expenses for the year ended December 31, 2007 increased to $41.4 million ($2.16 per boe) compared to $40.1 million ($2.09 per boe) in 2006. For the three months ended December 31, 2007, transportation expenses decreased 5% to $10.4 million ($2.12 per boe) when compared to $10.9 million ($2.23 per boe) for the same period last year. The increase in transportation expenses year to date was primarily due to the increase in trucking costs per barrel for heavy oil along with an increase in heavy oil volumes. These increases have been offset by a decrease in natural gas transportation due to the expiry of certain firm export service obligations. Transportation expenses for the fourth quarter of 2007 decreased as compared to the same period in 2006 primarily as a result of lower realized gas transportation costs. Transportation expenses by product for the year ended December 31, 2007 were $0.44 per mcf for natural gas, $0.92 per bbl for light and medium oil and $3.18 per bbl for heavy oil compared to $0.43 per mcf for natural gas, $0.86 per bbl for light and medium oil and $2.87 per bbl for heavy oil for the same period in 2006. For the fourth quarter of 2007, transportation expenses by product were $0.43 per mcf for natural gas, $0.86 per bbl for light and medium oil and $3.19 per bbl for heavy oil compared to $0.46 per mcf for natural gas, $0.85 per bbl for light and medium oil and $3.12 per bbl for heavy oil for the same period a year ago.

General and administrative expenses - General and administrative expenses, after overhead recoveries, for the year ended December 31, 2007 increased 19% to $13.3 million from $11.2 million in the same period in 2006 and increased 3% to $3.6 million for the three months ended December 31, 2007 from $3.5 million in the same period in 2006. On a per boe basis, general and administrative expenses increased 21% for the year ended December 31, 2007 to $0.70 per boe from $0.58 per boe in the same period in 2006 and increased 3% for the three months ended December 31, 2007 to $0.74 per boe from $0.72 per boe in the same period in 2006. This increase is largely due to the higher staffing levels required to manage our operations and increasing general cost pressures currently experienced throughout the industry. In addition, through a services agreement with NuVista Energy Ltd., Bonavista provides certain administrative activities. The fee charged under this agreement was $1.4 million for the year ended December 31, 2007 as compared to $2.3 million in the same period in 2006 and $400,000 for the three months ended December 31, 2007 as compared to $698,000 in 2006**.** In connection with its Trust Unit Incentive Rights Plan, Bonavista also recorded a unit-based compensation charge of $7.4 million and $2.8 million for the year and three months ended December 31, 2007 respectively, compared to $4.9 million and $714,000 for the same periods in 2006.

Financing expenses - Financing expenses, which include interest expense on long-term debt and convertible debentures, increased to $35.2 million for the year ended December 31, 2007, from $27.0 million for the same period in 2006 and on a boe basis increased to $1.84 per boe for the year ended December 31, 2007 from $1.40 per boe in the same period in 2006. For the three months ended December 31, 2007, financing expenses increased to $10.9 million from $7.7 million for the same period in 2006 and on a boe basis increased to $2.24 per boe for the three months ended December 31, 2007 from $1.57 per boe for the same period in 2006. These increases are due to higher interest rates and increased debt levels used to fund Bonavista's capital program. Amortization and accretion expenses related to the Trust's convertible debentures for the year ended December 31, 2007 decreased to $777,000 from $860,000 for the same period in 2006. For the three months ended December 31, 2007 amortization and accretion expenses decreased to $192,000 from $197,000 for the same period in 2006. This decrease is largely attributable to the conversion of debentures into Trust Units since December 31, 2006. The amortization component reflects the charge to net income of the debenture issue costs over the term of the debenture. The fair value of the conversion option of the debentures is classified as equity. Over the term of the debentures, the carrying value will accrete to the principal balance at maturity, with the charge to accretion expense on convertible debentures. For the year ended December 31, 2007 Bonavista paid cash interest of $35.4 million compared to $26.8 million for the same period in 2006. During the fourth quarter of 2007, Bonavista paid cash interest of $11.3 million compared to $7.9 million in 2006.

Depreciation, depletion and accretion expenses - Depreciation, depletion and accretion expenses increased 8% to $231.9 million for the year ended December 31, 2007 from $214.7 million for the same period in 2006. For the three months ended December 31, 2007 depreciation, depletion and accretion expenses also increased by 8% to $60.5 million from $56.2 million in the same period of 2006. Both increases were due to higher costs of finding and developing reserves and a larger asset base in 2007. For the year ended December 31, 2007 the average cost increased to $12.10 per boe from $11.18 per boe for the same period in 2006 and for the three months ended December 31, 2007 the average cost increased to $12.39 per boe from $11.50 per boe for the same period a year ago. The increase in depreciation, depletion and accretion expenses are due to increased costs associated with adding reserves. Over the past few years our industry has seen tremendous cost escalation due to the heavy demand for oilfield services, in particular drilling and service rig activities. These costs are showing signs of alleviating, the result of an industry-wide slowdown due to the lower natural gas prices realized throughout the past year and the uncertainty surrounding the new Alberta Royalty framework.

Income taxes - For the year ended December 31, 2007, the provision for income taxes was a recovery of $535,000 compared to a recovery of $25.2 million for the same period of 2006. For the three months ended December 31, 2007, the provision for income tax was a recovery of $30.8 million compared to a recovery of $3.4 million for the same period in 2006. The income tax provision for the year ended December 31, 2007 includes a $36.4 million future income tax charge resulting from recent changes to income tax legislation substantively enacted in the second and fourth quarters of 2007 that modify the taxation of certain flow through entities, including mutual fund trusts and their unitholders. The provision arose as the book basis of the assets and liabilities held in the Trust and a subsidiary trust exceeded their tax basis. Previously, future income taxes were recorded only on the temporary differences in the corporate subsidiaries of the Trust. In addition, the provision for the year ended December 31, 2007 includes a recovery of $9.6 million related to tax rate reductions enacted during the second and fourth quarters of 2007. Bonavista made no cash payments relating to installments for either of the three months and year ended December 31, 2007, compared to nil and $785,000, respectively, for the same periods a year ago.

Funds from operations, net income and comprehensive income - For the year ended December 31, 2007, Bonavista experienced a 1% increase in funds from operations to $502.8 million ($4.76 per unit, basic) from $496.4 million ($4.86 per unit, basic) for the same period in 2006. For the three months ended December 31, 2007, Bonavista experienced a 5% increase in funds from operations to $127.8 million ($1.20 per unit, basic) from $121.3 million ($1.17 per unit, basic) for the same period in 2006. Funds from operations increased for the year and three months ended December 31, 2007 primarily due to higher realized oil and liquids product prices and higher oil and liquids volumes. Net income for the year ended December 31, 2007, decreased 28% to $218.2 million ($2.07 per unit, basic) from $301.3 million ($2.95 per unit, basic) for the same period of 2006. The decrease is largely due to higher depletion and depreciation expenses and the recognition of unrealized losses on financial instruments and the higher provisions for income taxes. For the three months ended December 31, 2007, net income decreased 6% to $63.6 million ($0.60 per unit, basic) from $67.6 million ($0.65 per unit, basic) for the same period in 2006. The decrease in net income, prior to the tax provision to reflect the enactment of the taxation changes, for the year ended December 31, 2007, was largely due to a recovery relating to the reduction in future federal and provincial income tax rates enacted during the fourth quarter of 2006 and the recognition of unrealized losses on financial instruments. Other comprehensive income for the year ended December 31, 2007 included a charge of $6.0 million, (2006 – nil) relating to the amortization of the amount recognized in accumulated other comprehensive income on January 1, 2007 for the fair value of financial instruments on adoption of the new accounting standards for financial instruments. This resulted in total comprehensive income for the year ended December 31, 2007 of $212.2 million (2006 – $301.3 million). Other comprehensive income for the three months ended December 31, 2007 included a charge of $2.5 million, (2006 – nil) relating to the amortization of the amount recognized in accumulated other comprehensive income on January 1, 2007 for the fair value of financial instruments on adoption of the new accounting standards for financial instruments. This resulted in total comprehensive income for the three months ended December 31, 2007 of $61.1 million (2006 – $67.6 million).

The following table is a reconciliation of a non-GAAP measure, funds from operations, to its nearest measure prescribed by GAAP:

Calculation of Funds From Operations:	**Three Months ended December 31,**		**Years ended December 31,**	
	2007	**2006**	**2007**	**2006**
(thousands)				
Cash flow from operating activities	$ 95,459	$ 94,456	$ 473,021	$ 475,050
Increase in non-cash working capital	27,535	23,987	21,424	15,694
Asset retirement expenditures	4,784	2,862	8,338	5,694
Funds from operations	$ 127,778	$ 121,305	$ 502,783	$ 496,438

Capital expenditures - Capital expenditures for the year ended December 31, 2007 were $366.4 million, which consisted of $267.7 million of exploitation and development spending and $98.7 million of net property acquisitions. The total capital expenditures of $366.4 million was slightly higher than budget due to an increase in our crown land expenditures and planned $8.5 million disposition of northeast Alberta natural gas assets to a junior oil and natural gas company that was not consummated. For the same period in 2006, capital expenditures were $316.4 million consisting of $280.6 million of exploitation and development spending and $35.8 million of net property acquisitions. Capital expenditures for the three month period ended December 31, 2007 were $58.0 million, consisting of $58.4 million on exploitation and development spending and $425,000 of dispositions. For the same period in 2006 capital expenditures were $58.4 million, consisting of $58.7 million of exploitation and development spending and $345,000 of dispositions. With the industry currently experiencing cost reductions in many of its services due to lower industry activity levels, Bonavista too is benefiting with its active drilling program which is generating production addition costs at attractive levels. Entering 2008, we continue to generate favourable economic returns from our capital expenditure program as a direct result of the recent decrease in service costs coupled with strengthening commodity prices.

The following table outlines capital expenditures by category for the years ended December 31, 2007 and 2006:

	Years ended December 31, 2007	2006
(thousands)		
Land acquisitions	$ 33,211	$ 20,608
Geological and geophysical	9,811	8,824
Drilling and completion	139,578	172,538
Production equipment and facilities	84,444	78,012
Other	616	581
Exploitation and development expenditures	267,660	280,563
Acquisitions	100,806	36,155
Dispositions	(2,110)	(365)
Net capital expenditures	**$ 366,356**	**$ 316,353**

Liquidity and capital resources - As at December 31, 2007, long-term debt including working capital deficiency, was $723.0 million with an attractive debt to 2007 funds from operations ratio of 1.4:1 (1.5:1 including convertible debentures). With our bank credit facility recently increased to $1.0 billion in August 2007, Bonavista has $277.0 million of unused bank borrowing capability, leaving significant flexibility to finance future expansions in our capital programs or acquisition opportunities as they arise.

In 2008, Bonavista plans to invest approximately $400 to $420 million to expand its core regions, which will be financed through a combination of funds from operations and bank debt. The Trust is committed to the fundamental principle of maintaining financial flexibility and the prudent use of debt. As such, the 2008 capital expenditure program is based on using a conservative amount of debt in our financing structure.

Under the terms of the credit facility, the Trust has provided the covenant that its consolidated senior debt borrowing will not exceed three times net income before interest, taxes and depreciation, depletion and accretion; consolidated total debt will not exceed three and one half times consolidated net income before interest, taxes and depreciation, depletion and accretion; and consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated unitholders' equity of the Trust.

Subsequent event - On January 14, 2008, we completed the acquisition of producing and undeveloped oil and natural gas properties in the Willesden Green area of our South Central Alberta core regions and the Fireweed area located in our Northeast British Columbia core region for proceeds of $167 million. The acquisition added approximately 3,800 boe per day; comprised of 14 mmcf per day of natural gas, 700 bbls per day of associated natural gas liquids and 800 bbls per day of light crude oil.

Unitholders' equity - As at December 31, 2007, Bonavista had 106.8 million equivalent trust units outstanding. This includes 12.2 million exchangeable shares, which are exchangeable into 21.1 million trust units. The exchange ratio in effect at December 31, 2007 for exchangeable shares was 1.72244:1. As at March 12, 2008, Bonavista had 107.7 million equivalent trust units outstanding. This includes 12.2 million exchangeable shares, which are exchangeable into 21.5 million trust units. The exchange ratio in effect at March 12, 2008 for exchangeable shares was 1.76049:1. In addition, Bonavista has 3.3 million trust unit incentive rights outstanding at March 12, 2008, with an average exercise price of $27.26 per trust unit.

As at December 31, 2007, Unitholders' equity included $1.1 million for the ascribed value of the conversion feature of the convertible debentures. This amount was determined at the time the debentures were issued and was subsequently reduced by the amounts attributed to debentures that have been converted into trust units. Of the 100,000, 7.5% convertible debentures issued on January 29, 2004, there have been 92,206 of these debentures converted into trust units, leaving 7,794 debentures with a principal amount of $7.8 million outstanding as at December 31, 2007. On December 31, 2004, the Trust issued 135,000, 6.75% convertible debentures in conjunction with a property acquisition in British Columbia. The original issue of these debentures had a principal amount of $135.0 million, and from the date of issuance to December 31, 2007 there have been 91,698 of these debentures converted into trust units, leaving 43,302 debentures outstanding with a principal amount of $43.3 million.

Contractual obligations - The following is a summary of the Trust's contractual obligations and commitments as at December 31, 2007:

	Payments Due by Period					
	Total	**2008**	**2009**	**2010**	**2011**	**2012 and thereafter**
(thousands)						
Long-term debt repayments [(1)]	$ 712,654	$ -	$ -	$ 712,654	$ -	$ -
Convertible debentures	51,096	-	7,794	43,302	-	-
Transportation expenses	24,706	12,657	8,127	1,324	953	1,645
Office premises	4,762	1,527	1,527	1,412	296	-
Total contractual obligations	**$ 793,218**	**$ 14,184**	**$ 17,448**	**$ 758,692**	**$ 1,249**	**$ 1,645**

(1) Based on the existing terms of the revolving credit facility, the first payment may be required in 2010. However, it is expected that the revolving credit facility will be extended and no repayments will be required in the near term.

Distributions – Bonavista's distribution policy is constantly monitored and is dependent upon its forecasted operations, funds from operations, debt levels and capital expenditures. One of the paramount objectives of the Trust is to be a sustainable entity, which is defined as maintaining both production and reserves over an extended period of time. This is accomplished by retaining sufficient funds from operations to replace the reserves that have been produced. With these considerations, for the year ended December 31, 2007 the Trust declared distributions of $307.4 million compared to $324.0 million in the same period in 2006. For the three months ended December 31, 2007 the Trust declared distributions of $77.1 million compared to $76.3 million in the same period in 2006.

The following table illustrates the relationship between cash flow provided from operating activities and distributions declared, as well as net income and distributions declared. Net income includes significant non-cash charges that do not impact cash flow. For the year and three months ended December 31, 2007, the non-cash charges amounted to $284.6 million and $64.1 million respectively compared to $195.2 million and $53.7 million for the same periods in 2006. Net income also includes fluctuations in future income taxes due to changes in tax rates and tax rules. In addition, other non-cash charges, such as depreciation, depletion and accretion and unrealized gains and losses on financial instruments, do not represent the actual cost of maintaining our productive capacity given the natural declines associated with oil and gas assets. In these instances, where distributions exceed net income, a portion of the cash distribution paid to Unitholders may be considered an economic return of Unitholders' capital.

	Three Months ended December 31,		Years ended December 31,	
Distribution Analysis	**2007**	**2006**	**2007**	**2006**
(thousands)				
Cash flow provided from operating activities	$ 95,459	$ 94,456	$ 473,021	$ 475,050
Net income	63,631	67,635	218,187	301,270
Distributions declared	77,136	76,296	307,401	324,016
Excess of cash flow provided from operating activities over distributions declared	18,323	18,160	165,620	151,034
Excess (shortfall) of net income over distributions declared	(13,505)	(8,661)	(89,214)	(22,746)

Bonavista announces its distribution policy on a quarterly basis. Distributions are determined by the Board of Directors and are dependent upon the commodity price environment, production levels, and the amount of capital expenditures to be financed from funds from operations. Bonavista's current monthly distribution rate is $0.30 per trust unit. This monthly distribution is comprised of the base distribution of $0.28 per trust unit plus a supplementary distribution of $0.02 per unit, due to the average realized commodity prices in excess of budget prices. The base distribution rate assumes realized commodity prices of CDN $8.00 per gj at AECO for natural gas and CDN $60.00 per barrel at Edmonton for light crude (this equates to approximately US $9.30 per mmbtu for NYMEX natural gas and US $60.00 per barrel for WTI crude oil). The combined base and supplementary distribution incorporates the withholding of sufficient funds from operations to fund capital expenditures required to maintain or modestly grow the current production base and provide sustainable distributions in the long-term. Our long-term objective is to distribute between 50% and 60% of our funds from operations. Our current distribution rate of $0.30 per trust unit per month places us in this range for 2008, based on the current market of commodity price futures.

Annual financial information - The following table highlights selected annual financial information for each of the three years ended December 31, 2007, 2006 and 2005:

Years ended December 31,	**2007**	**2006**	**2005**
(thousands, except per unit amounts)			
Consolidated Statement of Operations Information:			
Production revenues, net of royalties	$ 755,760	$ 735,176	$ 730,733
Funds from operations	502,783	496,438	522,649
Per unit – basic	4.76	4.86	5.41
Per unit – diluted	4.69	4.74	5.17
Net income	218,187	301,270	302,942
Per unit – basic	2.07	2.95	3.14
Per unit – diluted	2.06	2.90	3.05
Consolidated Balance Sheet Information:			
Total capital expenditures	$ 366,356	$ 316,353	$ 295,052
Total assets	2,242,057	2,067,931	1,934,892
Working capital (deficiency)	(10,349)	(6,125)	(27,907)
Long-term debt	712,654	512,323	343,802
Unitholders' equity	1,060,967	1,130,253	1,103,510
Distributed declared	307,401	324,016	270,827

Quarterly financial information - The following table highlights Bonavista's performance for the eight quarterly periods ending on March 31, 2006 to December 31, 2007:

	2007				**2006**			
	December 31	**September 30**	**June 30**	**March 31**	**December 31**	**September 30**	**June 30**	**March 31**
($ thousands, except per unit amounts)								
Production revenues	242,361	219,885	223,878	225,222	220,484	227,270	229,492	232,833
Net income	63,631	58,990	33,936	61,630	67,635	70,800	87,425	75,410
Net income per unit:								
Basic	0.60	0.56	0.32	0.59	0.65	0.69	0.86	0.75
Diluted	0.59	0.55	0.32	0.59	0.65	0.68	0.84	0.74

Production revenue, excluding gains and losses on financial instruments were 4% higher in the fourth quarter of 2007 versus the first quarter of 2006, primarily due to both slightly higher production volumes and average product prices. Net income decreased 16% in the fourth quarter of 2007 as compared to the first quarter of 2006. The decrease in net income in the fourth quarter of 2007 is attributed to a $31.5 million charge to net income to reflect the unrealized losses on financial instruments. The decrease in net income in the second quarter of 2007 is attributable to the non-cash future income tax charge to net income of $41.0 million to reflect recent changes to income tax legislation, substantially enacted in the second quarter of 2007.

Disclosure and Internal Controls - Disclosure controls and procedures have been designed to ensure that information required to be disclosed by Bonavista is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosures. The Chief Executive Officer and Chief Financial Officer have concluded, as of the end of the period covered by the interim filings, that Bonavista's disclosure controls and procedures are effectively designed to provide reasonable assurance that material information related to the issuer is made known to them by others within the Trust. It should be noted that while the Trust's Chief Executive Officer and Chief Financial Officer believe that the disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

Internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of the Trust's financial reporting and compliance with generally accepted accounting principles ("GAAP"). The CEO and CFO have evaluated the Trust's internal controls over financial reporting as at December 31, 2007 based on the framework in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") and have concluded they are sufficiently designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with GAAP. During the quarter ended December 31, 2007, there have been no changes to the Trust's internal controls over financial reporting that have materially, or are reasonably likely to, materially affect the internal controls over financial reporting.

Because of their inherent limitations, disclosure controls and procedures and internal controls over financial reporting may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance, that the objectives of the control systems are met.

Financial Reporting Update - Effective January 1, 2007, Bonavista adopted Canadian Institute of Chartered Accountants ("CICA") Section 3855, "Financial Instrument Recognition and Measurement" Section 3865, "Hedges" Section 1530, "Comprehensive Income", and Section 3861, "Financial Instruments – Disclosure and Presentation". These standards have been adopted prospectively. See note 3 to the consolidated financial statements. On December 1, 2006 the CICA issued three new accounting standards, Section 1535, "Capital Disclosures", Section 3862, "Financial Instruments – Disclosures" and Section 3863, "Financial Instruments – Presentation". These three new standards will require additional disclosure in the Trust's financial statements commencing January 1, 2008. The Trust will be required to adopt Section 3064 “Goodwill and Intangible Assets” on January 1, 2009. Canada’s Accounting Standards Board confirmed January 1, 2011 as the effective date for complete convergence of Canadian GAAP to International Financial Reporting Standards (“IFRS”). The Trust will continue to monitor and assess the impact of the planned convergence of Canadian GAAP with IFRS.

Update on Regulatory Matters - On October 25, 2007, the Government of Alberta released its much anticipated New Royalty Framework ("NRF"). The NRF was the government's response to a report issued September 18, 2007 by the Alberta Royalty Review Panel, which was commissioned by the Government of Alberta to perform a review of the province's royalty system to, in their words, ensure that the people of Alberta were receiving their "Fair Share" for the resources being extracted by the oil and gas industry. The full NRF is available at www.energy.gov.ab.ca. The NRF is anticipated to take effect January 1, 2009, this will result in the Trust's royalty rates for the low value sensitivity case to increase by less than one percent. Using GLJ's forecasted prices as at January 1, 2008 and a 10% discount rate will decrease the net present value of the Trust's reserves by less than two percent. Given the recent strength in commodity prices, the NRF will significantly impact the net present value of the Trust's reserves, however, at this time the full extent of the impact is not determinable, as the proposed framework has not been enacted.

Environmental Matters - On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "Action Plan") also known as ecoACTION, which includes the Regulatory Framework for Air Emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy-using products. Regarding large industry and industry related projects, the Government's Action Plan intends to achieve the following: (i) an absolute reduction of 150 megatonnes in greenhouse gas emissions by 2020 by imposing mandatory targets; and (ii) air pollution from industry is to be cut in half by 2015 by setting certain targets. New facilities using cleaner fuels and technologies will have a grace period of three years. In order to facilitate the companies' compliance with the Action Plan's requirements, while at the same time allowing them to be cost-effective, innovative and adopt cleaner technologies, certain options are provided. These are: (i) in-house reductions; (ii) contributions to technology funds; (iii) trading of emissions with below-target emission companies; (iv) offsets; and (v) access to Kyoto's Clean Development Mechanism.

On March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "Updated Action Plan") which provides some additional guidance with respect to the Government of Canada's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050. The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including oil and natural gas producers. The Updated Action Plan is intended to force industry to reduce greenhouse gas emissions and to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emissions and establish a market price for carbon. The Updated Action Plan provides for: (i) mandatory reductions of 18% from the 2006 baseline starting in 2010 and by an additional 2% in subsequent years for existing facilities; and (ii) new facilities built between 2004 and 2011 will have mandatory emissions standards based upon clean fuel standards (natural gas) with a 2% reduction below the third years intensity levels. For the upstream oil and natural gas industry the Updated Action Plan also provides for a company threshold of 10,000 boe per day and a facility threshold of 3,000 tonnes of CO2.

On March 8, 2007, the Alberta Government introduced Bill 3, the *Climate Change and Emissions Management Amendment Act,* which intends to reduce greenhouse gas emission intensity from large industries. Bill 3 states that facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emission intensity by 12% starting July 1, 2007; if such reduction is not initially possible the companies owning the large emitting facilities will be required to pay $15 per tonne for every tonne above the 12% target. These payments will be deposited into an Alberta-based technology fund that will be used to develop infrastructure to reduce emissions or to support research into innovative climate change solutions. As an alternate option, large emitters can invest in projects outside of their operations that reduce or offset emissions on their behalf, provided that these projects are based in

Alberta. Prior to investing, the offset reductions offered by a prospective operation, must be verified by a third party to ensure that the emission reductions are real.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, at this time it is not possible to predict the impact of those requirements on Bonavista's operations and financial condition although it is thought to be an immaterial amount.

Critical Accounting Estimates **-** The consolidated financial statements have been prepared in accordance with Canadian GAAP. A summary of significant accounting policies are presented in note 2 of the Notes to the Consolidated Financial Statements. Certain accounting policies are critical to understanding the financial condition and results of operations of Bonavista.

a) ***Proved oil and natural gas reserves -*** Proved oil and natural gas reserves, as defined by the Canadian Securities Administrators in National Instrument 51-101 with reference to the Canadian Oil and Natural Gas Evaluation Handbook, are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   An independent reserve evaluator using all available geological and reservoir data as well as historical production data has prepared Bonavista's oil and natural gas reserve estimates. Estimates are reviewed and revised as appropriate. Revisions occur as a result of changes in prices, costs, fiscal regimes, reservoir performance or a change in the Trust's development plans. The effect of changes in proved oil and natural gas reserves on the financial results and position of the Trust is described below.

b) ***Depreciation, depletion and accretion expense*** - Bonavista uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves. Changes in estimated proved reserves or future development costs have a direct impact on depreciation and depletion expense.

   Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depreciation and depletion expense.

c) ***Full cost accounting ceiling test*** - The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

d) ***Asset retirement obligations*** - The asset retirement obligations are estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonment and reclamation discounted at a credit adjusted risk free rate. The costs are included in property, plant and equipment and amortized over their useful life. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

e) ***Income taxes*** **-** The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

Assessment of Business Risks

The following are the primary risks associated with the business of the Trust. These risks are similar to those affecting others in the conventional energy trust sector. The Trust's financial position, results of operations and distributions to Unitholders are directly impacted by these factors and include:

1) operational risk associated with the production of oil and natural gas;
2) reserve risk in respect to the quantity and quality of recoverable reserves;
3) market risk relating to the availability of transportation systems to move the product to market;
4) commodity risk as crude oil and natural gas prices fluctuate due to market forces;
5) financial risk such as volatility of the Canadian/US dollar exchange rate, interest rates and debt service obligations;
6) potential risk of change in distributions;
7) environmental and safety risk associated with well operations and production facilities;
8) changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices and environmental protection relating to the oil and natural gas industry and the income trust sector;
9) potential risk of liability to Unitholders resident in jurisdictions where there is no statutory protection for Unitholders from liabilities of the Trust;
10) continued participation of the Trust's lenders; and
11) counterparty risk with respect to non-performance by counterparties to financial derivative contracts.

The Trust seeks to mitigate these risks by:

1) acquiring mature properties with well established production trends to reduce technical uncertainty;
2) acquiring long life reserves to ensure more stable production and to reduce the economic risks associated with commodity price cycles;
3) maintaining a low cost structure to maximize product netbacks and reduce impact of commodity price cycles;
4) diversifying properties to mitigate individual property and well risk;
5) maintaining product mix to balance exposure to commodity prices;
6) conducting rigorous reviews of all property acquisitions;
7) monitoring pricing trends and developing a mix of contractual arrangements for the marketing of products with creditworthy counterparties;
8) maintaining a hedging program to hedge commodity prices and foreign exchange currency rates with creditworthy counterparties;
9) ensuring strong third party-operators for non-operated properties;
10) adhering to the Trust's safety program and keeping abreast of current operating best practices;
11) keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
12) carrying insurance to cover losses and business interruption; and
13) establishing and maintaining adequate cash resources to fund future abandonment and site restoration costs.

OUTLOOK

As we progress into our eleventh year since restructuring the Company in 1997, we continue to benefit from all of the same qualities that drove the success of Bonavista Petroleum Ltd. as a public company and an energy trust. We apply similar proven principles and execute our strategy in a disciplined and cost-effective manner much the same as in 1997 when we started on this mission of value creation. The foundation of this strategy is to actively pursue low to medium risk drilling opportunities on the extensive undeveloped land base within our geographically concentrated areas of operations. Despite a very active exploitation and development program over the past year, the quality and quantity of our drilling opportunities continues to increase as we transition from 2007 into 2008. This increase in inventory can be directly attributed to the detailed and tireless work of our talented technical team, who possess a strong commitment and a solid understanding of the Western Canadian Sedimentary Basin. We also continue to search for strategic acquisition opportunities where we can add value utilizing our own technical expertise. This period of commodity price volatility and market uncertainty should benefit Bonavista in the near future due to its proven track record of timely acquisitions and our strong balance sheet. In late 2007, we witnessed acquisition prices decreasing to a level that compares favourably with our cost of adding reserves organically and we acted on this by committing to a $167 million natural gas-weighted property acquisition, which was completed in January 2008. Our prudent approach to capital investment has been very effective in the past and together with our steadfast commitment to adding Unitholder value and attention to detail will continue to provide the foundation for the future success of the Trust. Today our activity, efficiency, productivity and profitability remain among the strongest levels in our ten year history.

As a result of completing this strategic property acquisition in the first quarter of 2008, Bonavista is pleased to announce that its Board of Directors has approved an expanded operating and capital program for 2008. However, in light of the current volatility in equity and commodity markets, Bonavista has decided to take a somewhat conservative approach and proceed with a base capital budget of $400 to $420 million which includes no further acquisition capital beyond the $167 million acquisition. The remainder of the capital program will be allocated to Bonavista's exploration, exploitation and development programs which includes drilling approximately 200 to 220 wells on existing and recently acquired lands in our core regions. It is anticipated that the base capital program should result in Bonavista's 2008 production volumes averaging approximately 54,000 to 54,500 boe per day. This level of production factors in significant downtime anticipated in the second and third quarters, primarily due to two major third party plant turnarounds. Assuming current commodity prices in the futures market are realized, Bonavista's 2008 cashflow should increase to approximately $640 to $650 million. Bonavista has currently identified over 680 drilling prospects on its current land base and may accelerate the drilling of some of these prospects in the latter half of 2008, should market conditions warrant. In the interim, Bonavista will proceed prudently and methodically with its stated drilling program in the first half of the year to allow for maximum financial flexibility and remain opportunistic to further expand its capital program on additional acquisitions and/or drilling opportunities.

We are extremely proud of our achievements over our past ten years and are very excited about the growing opportunities that exist for Bonavista in the future. We would like to thank our employees for their significant effort and their continued enthusiasm and excitement as we pursue these opportunities. Despite the passage of legislation in the Canadian House of Commons on the taxation of distributions from certain publicly traded Canadian trusts and the introduction of the NRF by the Government of Alberta, Bonavista's value creation process has not changed. Throughout many business cycles and changes in the business environment, Bonavista has thrived. Our success is based on the consistent application of our core philosophy and operating strategies. Our corporate structure may ultimately change by 2011 when the new tax laws are introduced but our proven strategy will not change under this new tax regime nor the provincial government's new royalty regime, as our team remains dedicated to add Unitholder value in the oil and natural gas business, regardless of the changing landscape.

On behalf of the Board of Directors

Keith A. MacPhail
Chairman, President and
Chief Executive Officer

Ronald J. Poelzer
Executive Vice President and
Chief Financial Officer

March 12, 2008
Calgary, Alberta

MANAGEMENT'S REPORT

The preparation of the accompanying consolidated financial statements in accordance with accounting principles generally accepted in Canada is the responsibility of management. Financial information contained elsewhere in this Annual Report is consistent with that in the consolidated financial statements.

Management is responsible for the integrity and objectivity of the financial statements. Where necessary, the financial statements include estimates, which are based on management's informed judgments. Management has established systems of internal controls, which are designed to provide reasonable assurance those assets, are safeguarded from loss or unauthorized use and to produce reliable accounting records for the preparation of financial information.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the Audit Committee, all of whose members are non-management directors. The Audit Committee has reviewed the consolidated financial statements with management and the auditors and has reported to the Board of Directors, which have approved the consolidated financial statements.

KPMG LLP are independent auditors appointed by Bonavista's unitholders. The auditors have considered, for the purposes of determining the nature, timing and extent of their audit procedures, the Trust's internal controls and have audited the consolidated financial statements in accordance with generally accepted auditing standards to enable them to express an opinion on the fairness of the financial statements in accordance with Canadian generally accepted accounting principles.

Keith A. MacPhail
President and
Chief Executive Officer

Ronald J. Poelzer
Executive Vice President and
Chief Financial Officer

March 12, 2008
Calgary, Alberta

AUDITORS' REPORT TO THE UNITHOLDERS

We have audited the consolidated balance sheets of Bonavista Energy Trust as at December 31, 2007 and 2006 and the consolidated statements of operations, comprehensive income and accumulated earnings and cash flows for the years then ended. 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.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 12, 2008

BONAVISTA ENERGY TRUST
Consolidated Balance Sheets

December 31, (thousands)	2007	2006
Assets:		
Current Assets:		
Accounts receivable	$ 112,226	$ 116,251
Future income tax asset (note 10)	13,517	-
	125,743	116,251
Oil and natural gas properties and equipment (note 6)	2,074,993	1,910,359
Goodwill	41,321	41,321
	$ 2,242,057	$ 2,067,931
Liabilities and Unitholders' Equity:		
Current liabilities:		
Accounts payable and accrued liabilities	$ 91,034	$ 122,376
Unrealized financial instruments (note 11)	45,058	-
	136,092	122,376
Long-term debt and other obligations (note 7)	712,654	514,169
Convertible debentures (note 8)	48,830	51,170
Asset retirement obligations (note 5)	116,893	96,324
Future income taxes (note 10)	166,621	153,639
Unitholders' equity:		
Unitholders' capital (note 9)	850,631	834,625
Exchangeable shares (note 9)	74,710	75,121
Contributed surplus (note 9)	9,369	4,973
Convertible debentures (note 8)	1,054	1,117
Accumulated earnings	125,203	214,417
	1,060,967	1,130,253
Commitments (note 12)		
	$ 2,242,057	$ 2,067,931

See accompanying notes to the consolidated financial statements.

Approved on behalf of Bonavista Energy Trust, by Bonavista Petroleum Ltd. as administrator:

Ian S. Brown, Director

Michael M. Kanovsky, Director

BONAVISTA ENERGY TRUST

Consolidated Statements of Operations, Comprehensive Income and Accumulated Earnings

Years ended December 31,	**2007**	**2006**
(thousands, except per unit amounts)		
Revenues:		
Production	$ 911,346	$ 910,079
Royalties	(155,586)	(174,903)
	755,760	735,176
Realized losses on financial instruments	(665)	(8,332)
Unrealized losses on financial instruments (note 11)	(45,058)	-
	710,037	726,844
Expenses:		
Operating	162,371	152,087
Transportation	41,397	40,065
General and administrative	13,335	11,229
Financing	35,209	26,960
Unit-based compensation	7,351	4,890
Depreciation, depletion and accretion	232,722	215,558
	492,385	450,789
Income before taxes	217,652	276,055
Income taxes (reductions) (note 10)	(535)	(25,215)
Net income	218,187	301,270
Changes in comprehensive income, net of taxes	(5,994)	-
Comprehensive income	212,193	301,270
Accumulated earnings, beginning of year	214,417	237,163
Distributions declared	(307,401)	(324,016)
Accumulated earnings, end of year	$ 125,203	$ 214,417
Net income per unit – basic	$ 2.07	$ 2.95
Net income per unit – diluted	$ 2.06	$ 2.90

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY TRUST
Consolidated Statements of Cash Flows

Years ended December 31,	**2007**	**2006**
(thousands, except per unit amounts)		
Cash provided by (used in):		
Operating Activities:		
Net income	$ 218,187	$ 301,270
Items not requiring cash from operations:		
Depreciation, depletion and accretion	232,722	215,558
Unit-based compensation	7,351	4,890
Unrealized losses on financial instruments	45,058	-
Future income taxes (reductions)	(535)	(25,280)
Asset retirement expenditures	(8,338)	(5,694)
Changes in non-cash working capital items	(21,424)	(15,694)
	473,021	475,050
Financing Activities:		
Issuance of equity, net of issue costs	8,144	5,936
Distributions	(307,125)	(325,064)
Changes in long-term debt	200,331	168,521
Changes in non-cash working capital items	(164)	121
	(98,814)	(150,486)
Investing Activities:		
Exploitation and development	(267,660)	(280,563)
Business acquisitions (note 4)	-	(25,800)
Property acquisitions	(100,806)	(10,355)
Property dispositions	2,110	365
Changes in non-cash working capital items	(7,851)	(8,211)
	(374,207)	(324,564)
Change in cash	-	-
Cash, beginning of year	-	-
Cash, end of year	$ -	$ -

See accompanying notes to the consolidated financial statements.

Notes to Consolidated Financial Statements

Years ended December 31, 2007 and 2006

1. Structure of the Trust and Basis of Presentation:

Bonavista Energy Trust ("Bonavista" or the "Trust") is an open-ended unincorporated investment trust governed by the laws of the Province of Alberta. The Trust was established on July 2, 2003 under a Plan of Arrangement entered into by the Trust, Bonavista Petroleum Ltd. ("BPL") and its subsidiaries and partnerships and NuVista Energy Ltd. ("NuVista"). Under the Plan of Arrangement, a wholly-owned subsidiary of the Trust amalgamated with BPL and became the successor company. The Trust has two significant subsidiaries in which it owns 100% of the common shares of BPL (excluding the exchangeable shares – see note 9) and 100% of the units of Bonavista Trust (2003) ("BT"). The activities of these entities are financed through interest bearing notes from the Trust and third party debt as described in the notes to the consolidated financial statements. The business of the Trust is carried on through the entities owned by the subsidiaries of the Trust, Bonavista Petroleum, a general partnership ("BP") and Bonavista Energy Limited Partnership ("BELP"). The net income of the Trust is generated from interest on notes advanced to its subsidiaries, royalty payments on oil and natural gas assets owned by BP, as well as any dividends or distributions paid by its subsidiaries. The Trustee must declare payable to the Trust Unitholders all of the taxable income of the Trust.

2. Significant accounting policies:

As determination of many assets, liabilities, revenues and expenses is dependent upon future events, the preparation of these consolidated financial statements requires the use of estimates and assumptions, which have been made using careful judgement. In particular, the amounts recorded for depreciation, depletion and accretion of the oil and natural gas properties and for asset retirement obligations are based on estimates of reserves and future costs. By their nature, these estimates, and those related to future cash flows used to assess impairment, are subject to measurement uncertainty and the impact on the financial statements of future periods could be material. In the opinion of management, these consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

a) Principles of consolidation:

The consolidated financial statements include the accounts of the Trust and its wholly-owned subsidiaries, trusts and proportionate share of its partnerships. All inter-entity transactions have been eliminated.

b) Oil and natural gas properties and equipment:

The Trust follows the full cost method of accounting, whereby all costs associated with the exploration for and development of oil and natural gas reserves are capitalized in cost centres on a country-by-country basis. Such costs include land and property acquisitions, geological and geophysical activities, drilling, well equipment and facilities. Gains or losses are not recognized upon disposition of oil and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion by 20% or more.

Costs capitalized in the cost centres, including well equipment, together with estimated future capital costs associated with proven reserves, are depreciated and depleted using the unit-of-production method which is based on gross production and estimated proven oil and natural gas reserves as determined by independent engineers. The cost of unproven properties is excluded from the depreciation and depletion base. For purposes of the depreciation and depletion calculations, oil and natural gas reserves are converted to a common unit of measure on the basis of their relative energy content, being six thousand cubic feet of natural gas for one barrel of oil. Facilities are depreciated using the declining balance method over their useful lives, which range from 12 to 15 years.

Oil and natural gas properties and equipment are evaluated in each reporting period to determine whether the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre. The carrying amounts are assessed to be recoverable when the sum of the undiscounted future cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects of the cost centre. The cash flows are estimated using expected future product prices and costs, and are discounted using a risk-free interest rate.

c) Joint operations:

A portion of Bonavista's oil and natural gas operations are conducted jointly with others. Accordingly, the consolidated financial statements reflect only Bonavista's proportionate interest in such activities.

d) Goodwill:

Goodwill is tested for impairment on an annual basis in the fourth quarter of each year. If indications of impairment are present, a loss would be charged to net income for the amount that the carrying value of goodwill exceeds its fair value.

e) Asset retirement obligations:

Bonavista records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability.

f) Revenue recognition:

Revenues from the sale of oil and natural gas are recorded when title passes to an external party.

g) Financial instruments:

i) A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition, all financial instruments, including all derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and other liabilities. The Trust has designated its cash and cash equivalents and investments, other than equity investments, as held for trading which are measured at fair value. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Accounts payable and accrued liabilities, distributions payable and bank debt are classified as other liabilities which are measured at amortized cost, which is determined using the effective interest method. The convertible debentures are classified as debt on the balance sheet with a portion of the proceeds allocated to equity. The debt component has been measured at amortized cost.

ii) The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments may be used by the Trust to reduce its exposure to fluctuations in commodity prices, foreign exchange rates, and interest rates. The Trust does not use these derivative instruments for trading or speculative purposes. The Trust considers all of these transactions to be economic hedges, however, the majority of the Trust's contracts do not qualify or have not been designated as hedges for accounting purposes. As a result, all derivative contracts are classified as held for trading and are recorded on the balance sheet at fair value, with changes in the fair value recognized in net income, unless specific hedge criteria are met. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity given future market prices and other relevant factors. Proceeds and costs realized from holding the derivative contracts are recognized in net income at the time each transaction under a contract is settled. The Trust has elected to account for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts on an accrual basis rather than as non-financial derivatives. The Trust nets all transaction costs incurred, in relation to the acquisition of a financial asset or liability, against the related financial asset or liability. In accordance with this policy convertible debentures are recorded net of issue costs and bank debt is presented net of deferred interest payments, with interest recognized in net income on an effective interest basis.

h) Unit-based compensation:

Bonavista has an equity incentive plan, which is described in note 9. The trust unit incentive right compensation plan for employees do not involve the direct award of trust units, or call for the settlement in cash or other assets. Bonavista uses the fair value method for valuing the granting of trust unit incentive rights. Under this method, the compensation cost attributable to all the trust unit rights granted is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the trust unit rights, consideration received together with the amount previously recognized in contributed surplus is recorded as an increase to Unitholders' equity.

i) Restricted trust unit incentive plan:

Bonavista has established a Restricted Trust Unit Incentive Plan (the "RTU Plan") for our employees as described in note 9. Vesting arrangements are within the discretion of our board of directors, but all awards will vest within three years from the date of grant. On the vesting date the holder will receive either: (i) one trust unit; or (ii) the cash equivalent of one trust unit for each unit award as well as all distributions made on trust units from the date of grant to and including the vesting date at the discretion of the Trust. Trust units may be issued from treasury or purchased on the open market. The Trust has not incorporated an estimated forfeiture rate for Restricted Trust Units that will not vest, rather the Trust accounts for actual forfeitures as they occur.

j) Income taxes:

Bonavista is a taxable entity under the Canadian Income Tax Act and until 2011 is taxable only on income that is not distributed or distributable to its unitholders. Commencing in 2011, distributions paid to unitholders will not be deductible for tax and Bonavista will be taxed on its income similar to corporations. The Trust follows the asset and 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 in the financial statements of BPL and its subsidiaries and their respective tax basis, using substantively enacted income tax rates expected to be in effect when the temporary differences are anticipated to reverse. In addition, income tax liabilities and assets are recognized for the estimated tax consequences of temporary differences arising in the Trust that reverse after 2011. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in net income in the period that the change occurs.

k) Per unit amounts:

Diluted per unit amounts reflect the potential dilution that could occur if securities or other contracts to issue trust units were exercised or converted to trust units. The treasury stock method is used to determine the dilutive effect of unit incentive rights and other dilutive instruments.

l) Comparative figures:

The comparative figures have been reclassified to reflect the current year presentation.

3. Changes in accounting policy:

Financial Instruments and Hedging Activities

Effective January 1, 2007, Bonavista adopted the Canadian Institute of Chartered Accountants ("CICA") Section 3855, "Financial Instruments – Recognition and Measurement", Section 3865, "Hedges", Section 1530, "Comprehensive Income", and Section 3861, "Financial Instruments – Disclosure and Presentation". Bonavista has adopted these standards prospectively and the comparative consolidated financial statements have not been restated. Transition amounts have been recorded in accumulated other comprehensive income.

As at January 1, 2007, the following adjustments were made to the consolidated balance sheet on adoption of the new standards:

(thousands)		**January 1, 2007**
Accounts receivable – financial instruments	$	8,563
Future income taxes		(2,569)
Accumulated other comprehensive income		(5,994)

On December 1, 2006 the CICA issued three new accounting standards, Section 1535, "Capital Disclosures", Section 3862, "Financial Instruments – Disclosures" and Section 3863, "Financial Instruments – Presentation". These three new standards will require additional disclosure in the Trust's financial statements commencing January 1, 2008. The Trust will be required to adopt Section 3064 "Goodwill and Intangible Assets" on January 1, 2009. Canada's Accounting Standards Board confirmed January 1, 2011 as the effective date for complete convergence of Canadian GAAP to International Financial Reporting Standards ("IFRS"). The Trust will continue to monitor and assess the impact of the planned convergence of Canadian GAAP with IFRS.

4. Business relationships:

Bonavista and NuVista are considered related as two directors of NuVista, one of whom is NuVista's chairman, are directors and officers of Bonavista and a director and an officer of NuVista are also officers of Bonavista.

Pursuant to the Plan of Arrangement , Bonavista entered into a Technical Services Agreement ("TSA") with NuVista, whereby, Bonavista received payment for certain technical and administrative services provided by it to NuVista on a cost recovery basis. Effective January 1, 2007 the terms of the TSA were amended to reflect the reduced level of services provided by Bonavista and subsequently on August 31, 2007 the TSA was terminated and replaced with a new services agreement that reflects the remaining ongoing services that will be provided by Bonavista.

For the year ended December 31, 2007 NuVista paid Bonavista $1.4 million (2006 - $2.3 million) in fees relating to general and administrative services provided to NuVista, in addition NuVista charged Bonavista management fees for a jointly owned partnership totaling $1.4 million (2006 – nil). Bonavista also charged NuVista $975,000 (2006 – nil) for costs that are outside the TSA relating to NuVista's share of direct charges from third parties. As at December 31, 2007, the amount receivable from NuVista was $703,000 (2006 - $2.7 million).

On June 1, 2006, Bonavista acquired oil and natural gas properties through a partnership for cash consideration of $25.8 million and included the results of operations from the date of the acquisition. A director and an officer of Bonavista are related parties of the vendor. Bonavista purchased these oil and natural gas properties through a series of transactions, with the properties being acquired in an existing partnership owned approximately 24% by BP and 76% by NuVista Energy Ltd. In conjunction with the acquisition, Bonavista recognized $800,000 of asset retirement obligations.

5. Asset retirement obligations:

The Trust's asset retirement obligations result from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. For the year ended December 31, 2007 the Trust has changed its estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods, resulting in an increase of $16.0 million (2006 – nil). The Trust estimates the total undiscounted amount of expenditures required to settle its asset retirement obligations is approximately $540.9 million (2006 – $475.2 million) which will be incurred over the next 51 years. The majority of the costs will be incurred between 2010 and 2037. A credit-adjusted risk-free rate of 7.5% (2006 – 7.5%) and an inflation rate of 2% (2006 – 2%) were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	Years ended December 31, 2007	2006
(thousands)		
Balance, beginning of year	$ 96,324	$ 82,819
Accretion expense	7,333	6,279
Liabilities incurred	1,629	11,332
Liabilities acquired	3,976	1,588
Liabilities settled	(8,338)	(5,694)
Changes in assumptions	15,969	-
Balance, end of year	**$ 116,893**	**$ 96,324**

6. Oil and natural gas properties and equipment:

December 31, 2007	**Cost**	**Accumulated depreciation and depletion**	**Net book value**
(thousands)			
Oil and natural gas properties	$ 2,538,591	$ 948,248	$ 1,590,343
Facilities	601,209	119,139	482,070
Office equipment	6,099	3,519	2,580
	$ 3,145,899	**$ 1,070,906**	**$ 2,074,993**

December 31, 2006	**Cost**	**Accumulated depreciation and depletion**	**Net book value**
(thousands)			
Oil and natural gas properties	$ 2,218,407	$ 751,254	$ 1,467,153
Facilities	532,762	92,165	440,597
Office equipment	5,483	2,874	2,609
	$ 2,756,652	**$ 846,293**	**$ 1,910,359**

Unproved property costs of $159.3 million as at December 31, 2007 (2006 - $136.8 million) were excluded from the depreciation and depletion calculation. Future development costs of $135.2 million (2006 - $123.2 million) were included in the depreciation and depletion calculation.

Bonavista has calculated the ceiling test as of December 31, 2007. Based on the calculation, the present value of future net revenues from the Trust's proved reserves exceeds the carrying value of the Trust's oil and natural gas properties and equipment at December 31, 2007. The impairment test was calculated using the benchmark reference prices at January 1 for the years 2008 to 2013 and adjusted for commodity differentials specific to Bonavista.

Benchmark Reference Price Forecasts:

Year	**WTI Oil (US$/bbl)**	**AECO Gas (Cdn$/mmbtu)**	**USD/CAD Exchange Rates**
2008	92.00	6.75	1.00
2009	88.00	7.55	1.00
2010	84.00	7.60	1.00
2011	82.00	7.60	1.00
2012	82.00	7.60	1.00
2013	82.00	7.60	1.00
2014	82.00	7.80	1.00
2015	82.00	7.97	1.00
2016	82.02	8.14	1.00
2017	83.66	8.31	1.00
2018	85.33	8.48	1.00
Remainder (1)	2.0%	2.0%	1.00

(1) Escalated at 2% per year thereafter

7. Long-term debt:

The Trust has a $1.0 billion credit facility with a syndicate of chartered banks. This facility is an unsecured, covenant-based, extendible revolving facility and includes a $50 million working capital facility. The facility provides that advances may be made by way of prime rate loans, bankers' acceptances and/or US dollar LIBOR advances. These advances bear interest at the banks' prime rate and/or at money market rates plus a stamping fee. The facility is a three year revolving credit and may, at the request of the Trust with the consent of the lenders, be extended on an annual basis. At present, no principal payments are required under the credit facility until August 10, 2010.

Under the terms of the credit facility, the Trust has provided the covenant that its consolidated senior debt borrowing will not exceed three times net income before interest, taxes and depreciation, depletion and accretion; consolidated total debt will not exceed three and one half times consolidated net income before interest, taxes and depreciation, depletion and accretion; and consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated unitholders' equity of the Trust.

Financing expenses for the year ended December 31,2007 include interest on bank loans of $31.6 million (2006 - $22.4 million) and convertible debentures of $3.6 million (2006 - $4.5 million). For the year ended December 31, 2007, Bonavista paid cash interest of $35.4 million (2006 - $26.8 million). For the year ended December 31, 2007 the weighted average effective interest rate was 5.3% (2006 – 4.8%)

8. Convertible debentures:

On January 29, 2004, Bonavista issued $100 million principal amount of 7.5% unsecured subordinated convertible debentures. The issue costs related to this offering were $4.3 million. The debentures mature on June 30, 2009, pay interest semi-annually and are convertible at the option of the holder into Trust Units of Bonavista at $23.00 per Trust Unit plus accrued and unpaid interest. As at December 31, 2007 the principal amount outstanding was $7.8 million.

On December 31, 2004, Bonavista issued $135 million principal amount of 6.75% unsecured subordinated convertible debentures. The issue costs related to the offering were $5.4 million. The debentures mature on June 30, 2010, pay interest semi-annually and are convertible at the option of the holder into Trust Units of Bonavista at a price of $29.00 per Trust Unit, plus accrued and unpaid interest. As at December 31, 2007 the principal amount outstanding was $43.3 million.

The debt component of the debentures has been recorded net of the fair value of the conversion feature and issue costs. The fair value of the conversion feature of the debentures included in Unitholders' equity at the date of issue was $4.7 million. The issue costs are amortized to net income over the term of the obligation and the debt component of the obligation is adjusted for the amortization as well as for the portion of issue costs relating to conversions. The debt portion is accreted over the term of the obligation to the principal value on maturity with a corresponding charge to net income. The following table sets out the convertible debenture activities to December 31, 2007:

(thousands)	**Debt Component**	**Equity Component**
Balance, December 31, 2005	$ 87,866	$ 1,892
Accretion	115	-
Issue expenses related to conversions to trust units	629	-
Amortization of issue expenses	745	-
Conversion to trust units	(38,185)	(775)
Balance, December 31, 2006	51,170	1,117
Accretion	75	-
Issue expenses related to conversions to trust units	29	-
Amortization of issue expenses	702	-
Conversion to trust units	(3,146)	(63)
Balance, December 31, 2007	**$ 48,830**	**$ 1,054**

9. Unitholders' equity:

a) Authorized:

Unlimited number of voting trust units.

b) Issued and outstanding:

(i) Trust units:

(thousands)	**Number of Units**	**Amount**
Balance, December 31, 2005	80,288	$ 769,629
Issued on conversion of convertible debentures	1,491	38,185
Issued on conversion of exchangeable shares	2,526	17,249
Issued upon exercise of trust unit incentive rights	534	5,936
Issue costs, related to debenture conversions	-	(629)
Adjustment to equity component of debenture on conversion	-	775
Unit-based compensation	-	3,480
Balance, December 31, 2006	84,839	834,625
Issued on conversion of convertible debentures	125	3,146
Issued on conversion of exchangeable shares	110	411
Issued upon exercise of trust unit incentive rights	683	8,144
Issue costs, related to debenture conversions	-	(29)
Adjustment to equity component of debenture on conversion	-	63
Unit-based compensation	-	4,271
Balance, December 31, 2007	**85,757**	**$ 850,631**

Redemption right:

Unitholders may redeem their Trust Units at any time by delivering their Unit Certificates to the Trustee, together with a properly completed notice requesting redemption. The redemption amount per Trust Unit will be the lesser of 90% of the weighted average trading price of the Trust Units on the principal market on which they are traded for the 10 day period after the Trust Units have been validly tendered for redemption and the "closing market price" of the Trust Units. The redemption amount will be payable on the last day of the following calendar month. The "closing market price" will be the closing price of the Trust Units on the principal market in which they are traded on the date on which they were validly tendered for redemption, or, if there was no trade of the Trust Units on that date, the average of the last bid and ask prices of the Trust Units on that date. Cash payments for Units tendered for redemption are limited to $250,000 per month with redemption requests in excess of this amount, eligible to receive a note from BPL.

(ii) Contributed surplus:

		Amount
(thousands)		
Balance, December 31, 2005	$	2,456
Unit-based compensation expense		4,890
Unit-based compensation capitalized		1,107
Exercise of trust unit incentive rights		(3,480)
Balance, December 31, 2006		4,973
Unit-based compensation expense		7,351
Unit-based compensation capitalized		1,316
Exercise of trust unit incentive rights		(4,271)
Balance, December 31, 2007	**$**	**9,369**

(iii) Exchangeable shares:

Pursuant to the Plan of Arrangement, 15,999,999 exchangeable shares were authorized and issued. The exchangeable shares of BPL are exchangeable only into trust units based on the exchange ratio, which is adjusted monthly, to reflect the distribution paid on the trust units. As a result distributions are not paid on the exchangeable shares.

	Years ended December 31, 2007		2006	
	Number	**Amount**	**Number**	**Amount**
(thousands)				
Balance, beginning of year	12,297	$ 75,121	14,101	$ 92,370
Exchanged for trust units	(67)	(411)	(1,804)	(17,249)
Balance, end of year	**12,230**	**$ 74,710**	**12,297**	**$ 75,121**
Exchange ratio, end of year	1.72244	-	1.52443	-
Trust units issuable on exchange	**21,066**	**$ 74,710**	**18,747**	**$ 75,121**

On the tenth anniversary of the issuance of the Exchangeable Shares, subject to extension of such date by the Board of Directors of BPL, the Exchangeable Shares will be redeemed for Trust Units at a price equal to the value of that number of Trust Units based on the exchange ratio as at the last business day prior to the redemption date. BPL may redeem all but not less than all of the outstanding Exchangeable Shares at any time when the aggregate number of issued and outstanding Exchangeable Shares is less than 1,000,000. BPL will, at least 90 days prior to any redemption date, provide the registered holders with written notice of the prospective redemption. The redemption price is equal to that described previously.

c) Trust unit incentive rights plan:

The Trust has a unit incentive rights plan that allows the Trust to issue rights to acquire trust units to directors, officers, employees and service providers. The Trust is authorized to issue up to 4,882,225 unit rights, however, the number of trust units reserved for issuance upon exercise of the rights shall not at any time exceed 5% of the aggregate number of issued and outstanding trust units of the Trust. Trust unit incentive right exercise prices are equal to the market price for the trust units on the date that the unit rights are granted. If certain conditions are met, the exercise price per unit may be calculated by deducting from the grant price the aggregate of all distributions, on a per unit basis, made by the Trust after the grant date. The trust unit incentive rights granted under the plan vest over a four-year period and expire one year after each vesting date.

	Number of Trust Unit Incentive Rights	Weighted Average Exercise Price
Balance, December 31, 2005	2,937,525	21.86
Granted	1,514,100	33.92
Exercised	(534,450)	(11.11)
Cancelled	(218,700)	(26.34)
Reduction in exercise price	-	(3.42)
Balance, December 31, 2006	3,698,475	24.67
Granted	894,900	30.70
Exercised	(682,575)	(11.93)
Cancelled	(184,675)	(27.94)
Reduction in exercise price	-	(3.53)
Balance, December 31, 2007	**3,726,125**	**$ 24.76**
Exercisable, December 31, 2007	**925,750**	**$ 19.26**

The following table summarizes trust unit incentive rights outstanding and exercisable under the plan at December 31, 2007:

	Trust Unit Incentive Rights Outstanding			Trust Unit Incentive Rights Exercisable	
Range of exercise prices	Number outstanding at year-end	Weighted average remaining contractual life	Weighted average exercise price	Number exercisable at year-end	Weighted average exercise price
$ 1.00 – 15.00	353,050	0.9	$ 4.59	275,450	$ 3.09
15.00 – 30.00	3,294,075	3.4	26.77	629,975	25.95
30.01 – 32.00	79,000	3.1	31.05	20,325	31.05
$ 1.00 – 32.00	3,726,125	3.2	$ 24.76	925,750	$ 19.26

d) Unit-based compensation:

The Trust uses the fair value based method for the determination of the unit-based compensation costs. The fair value of each incentive right granted was estimated on the date of grant using the modified Black-Scholes option-pricing model. In the pricing model, the risk free interest was 3.5% (2006 – 3.5%); volatility of 31% (2006 - 25%); a forfeiture rate of 10% (2006 - 10%) and an expected life of 4.5 years. The fair value of the options granted in 2007 averages $8.44 (2006 - $7.96) per incentive right.

e) Restricted trust unit incentive plan:

The Trust has a Restricted Trust Unit Incentive Plan that allows the Trust to award trust units to directors, officers, employees and service providers. The number of restricted trust units available under the plan shall be limited to 5% of the aggregate number of issued and outstanding units of the Trust. Vesting arrangements are within the discretion of our board of directors, but all awards will vest within three years from the date of grant. On the vesting date the holder will receive either: (i) one trust unit; or (ii) the cash equivalent of one trust unit for each unit award as well as all distributions made on trust units from the date of grant to and including the vesting date at the discretion of the Trust. Trust units may be issued from treasury or purchased on the open market.

The following table summarizes the restricted trust unit's outstanding under the plan at December 31, 2007:

Balance, December 31, 2006	-
Granted	168,844
Forfeited	(9,105)
Balance, December 31, 2007	**159,739**

For the year ended December 31, 2007, the Trust expensed $2.2 million (2006 – nil) relating to the Restricted Trust Unit Incentive Plan.

f) Per unit amounts:

The following table summarizes the weighted average trust units, exchangeable shares and convertible debentures used in calculating net income per trust unit:

	Years ended December 31, 2007	2006
(thousands)		
Trust units	85,350	83,556
Exchangeable shares converted at the exchange ratio	20,193	18,600
Basic equivalent trust units	105,543	102,156
Convertible debentures	1,891	2,389
Trust unit incentive rights	641	1,070
Diluted equivalent trust units	**108,075**	**105,615**

For the purposes of calculating net income per trust unit on a diluted basis, the net income has been increased by $4.4 million (2006 – $5.4 million) with respect to the accretion, amortization and interest expense on the convertible debentures. For the year ended December 31, 2007 the Trust excluded 1.7 million (2006 – 789,000) weighted average trust unit incentive rights from the diluted unit calculation as they are anti-dilutive.

g) Accumulated other comprehensive income:

The following table summarizes the amounts recognized on adoption of the new accounting standards for financial instruments and also the amortization of the amount recognized in accumulated other income on January 1, 2007:

(thousands)		
Balance, January 1, 2007	$	-
Transition adjustment for discontinuance of hedge accounting, net of taxes of $2,569		5,994
Reclassification to net income during the year, net of taxes of $2,569		(5,994)
Balance, December 31, 2007	**$**	**-**

10. Income taxes:

The provision for income tax differs from the result which would have been obtained by applying the combined Federal and Provincial income tax rates to net income before taxes. This difference results from the following items:

		Years ended December 31, 2007		2006
Expected tax rate		32.6%		35.5%
(thousands)				
Expected tax expense	$	70,955	$	98,000
Effect of change in tax rate		(10,872)		(11,839)
Distributions to unitholders		(99,673)		(113,481)
SIFT tax, net of tax rate reduction		36,444		-
Other		2,611		2,105
Provision for income taxes (reductions)	**$**	**(535)**	**$**	**(25,215)**
The provision for income taxes consists of:				
Current	$	-	$	65
Future (reduction)		(535)		(25,280)
Provision for income taxes (reductions)	**$**	**(535)**	**$**	**(25,215)**

The significant components of future income tax assets and liabilities as at December 31 are:

		2007		2006
(thousands)				
Oil and natural gas properties	$	156,540	$	146,023
Facilities		38,599		36,513
Asset retirement obligations		(28,518)		(28,897)
Unrealized financial instruments		(13,517)		-
Future income taxes	**$**	**153,104**	**$**	**153,639**

For the year ended December 31, 2007 Bonavista paid tax installments of nil (2006 - $785,000).

11. Financial instrument activities:

a) Balance sheet financial instruments:

Bonavista's financial instruments recognized in the Consolidated Balance Sheet consist of accounts receivable, accounts payable, long-term debt, and other long-term obligations. The market deficit of the Trust's derivative financial instruments is $45.1 million. Unless otherwise noted, carrying values reflect the current fair value of the Trust's financial instruments. The estimated fair values of recognized financial instruments have been determined based on Bonavista's assessment of available market information and appropriate methodologies, or through comparisons to similar instruments. The fair market value of the convertible debentures as at December 31, 2007 is $52.5 million.

b) Commodity price contracts:

i) Financial instruments:

As at December 31, 2007, the Trust has hedged by way of costless collars to sell natural gas (gjs/d) and crude oil (bbls/d) as follows:

Volume	Average Price	Term
5,000 gjs/d	CDN$ 7.50 - CDN$ 10.55 – AECO	January 1, 2008 – March 31, 2008
5,000 gjs/d	CDN$ 7.00 - CDN$ 9.00 – AECO	April 1, 2008 – October 31, 2008
7,000 bbls/d	US$ 65.43 - US$ 78.58 – WTI	January 1, 2008 – December 31, 2008
1,000 bbls/d	CDN$ 49.00 - CDN$ 57.00 – Bow River	January 1, 2008 – December 31, 2008
2,000 bbls/d	US$ 65.00 - US$ 80.50 – WTI	January 1, 2009 – March 31, 2009

As at December 31, 2007, the market deficit of these derivative financial instruments was approximately $45.1 million.

ii) Physical purchase contracts:

As at December 31, 2007, the Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume	Average Price (CDN$ - AECO)	Term
20,000 gjs/d	$ 7.75 - $ 10.53	January 1, 2008 – March 31, 2008

c) Credit risk:

Portions of the Trust's accounts receivable are with joint operating partners in the oil and natural gas industry and are subject to normal industry credit risks. Purchasers of the Trust's oil and natural gas products are subject to an internal credit review designed to mitigate the risk of non-payment.

d) Interest rate risk:

The Trust is exposed to interest rate risk to the extent that changes in market interest rates will impact the Trust's bank debt which is subject to a floating interest rate.

e) Foreign currency:

While substantially all of the Trust's sales are denominated in Canadian dollars, the market prices in Canada for oil and natural gas are impacted by changes in the exchange rate between Canadian and United States dollar.

12. Commitments:

The following is a summary of the Trust's commitments as at December 31, 2007:

	Payments Due by Period					
	Total	**2008**	**2009**	**2010**	**2011**	**2012 and thereafter**
(thousands)						
Transportation expenses	$ 24,706	$ 12,657	$ 8,127	$ 1,324	$ 953	$ 1,645
Office premises	4,762	1,527	1,527	1,412	296	-
Total commitments	**$ 29,468**	**$ 14,184**	**$ 9,654**	**$ 2,736**	**$ 1,249**	**$ 1,645**

13. Subsequent events:

a) Property acquisition:

On January 14, 2008, the Trust completed the acquisition of producing and undeveloped oil and natural gas properties in the Willesden Green area of our South Central Alberta core region and the Fireweed area located in our Northeast British Columbia core region for a net purchase price of $167 million.

b) Financial instrument activities:

Subsequent to December 31, 2007, the Trust has entered into the following commodity contracts:

i) Financial instruments:

The Trust has hedged by way of costless collars to sell natural gas (gjs/d) and crude oil (bbls/d) as follows:

Volume	Average Price	Term
20,000 gjs/d	CDN$ 7.38 - CDN$ 8.46 – AECO	April 1, 2008 – October 31, 2008
2,000 bbls/d	CDN$ 61.00 - CDN$ 71.75 – Bow River	April 1, 2008 – December 31, 2008
1,000 bbls/d	US$ 85.00 - US$ 105.60 – WTI	January 1, 2009 – December 31, 2009

ii) Physical purchase contracts:

The Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume	Average Price (CDN$ - AECO)	Term
45,000 gjs/d	$ 7.19 - $ 8.36	April 1, 2008 – October 31, 2008
25,000 gjs/d	$ 7.65 - $ 9.65	November 1, 2008 – March 31, 2009

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The Bank of Nova Scotia
The Toronto-Dominion Bank
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