BONAVISTA ENERGY TRUST

ANNUAL REPORT 2008

Highlights

	Three months ended December 31, 2008	Three months ended December 31, 2007	Years ended December 31, 2008	Years ended December 31, 2007
Financial				
($ thousands, except per unit)				
Production revenues	221,782	242,361	1,234,391	911,346
Funds from operations [1]	131,741	127,778	643,876	502,783
Per unit [1] [2]	1.12	1.20	5.64	4.76
Distributions declared	85,824	77,136	332,540	307,401
Per unit	0.90	0.90	3.60	3.60
Percentage of funds from operations [1]	65%	60%	52%	61%
Net income	129,192	63,631	438,366	218,187
Per unit [2]	1.09	0.60	3.84	2.07
Total assets			2,543,240	2,242,057
Long-term debt, including working capital deficiency			600,518	723,003
Long-term debt, net of adjusted working capital [3]			654,500	691,462
Unitholders' equity			1,411,972	1,060,967
Capital expenditures:				
Exploitation and development	60,236	58,440	305,514	267,660
Acquisitions, net	(105)	(425)	176,783	98,696
Weighted average outstanding equivalent trust units: (thousands) [2]				
Basic	118,065	106,762	114,190	105,543
Diluted	119,905	109,102	116,468	108,075
Operating				
(boe conversion – 6:1 basis)				
Production:				
Natural gas (mmcf/day)	171	170	175	171
Oil and liquids (bbls/day)	24,733	24,775	24,079	24,034
Total oil equivalent (boe/day)	53,288	53,029	53,190	52,505
Product prices: [4]				
Natural gas ($/mcf)	7.52	6.74	8.30	6.95
Oil and liquids ($/bbl)	53.05	58.04	70.68	54.40
Operating expenses ($/boe)	9.91	8.58	9.45	8.47
General and administrative expenses ($/boe)	0.78	0.74	0.74	0.70
Cash costs ($/boe) [5]	11.87	11.56	11.87	11.01
Operating netback ($/boe) [6]	28.83	29.17	35.49	28.77

Highlights (cont'd)

	December 31, 2008	2007
Drilling (gross wells)	200	216
Natural gas	84	108
Oil	106	97
Average success rate	95%	95%
Reserves:		
Proved:		
Natural gas (bcf)	462.6	427.1
Oil and liquids (mbbls)	65,044	63,724
Total oil equivalent (mboe)	142,150	134,911
Proved and probable:		
Natural gas (bcf)	613.7	561.0
Oil and liquids (mbbls)	88,817	85,955
Total oil equivalent (mboe)	191,095	179,454
% Proved producing	59%	62%
% Proved	74%	75%
% Probable	26%	25%
Net present value of future cash flow before income taxes ($ millions):		
0% discount rate	7,465	6,116
5% discount rate	4,804	4,116
10% discount rate	3,555	3,154
Reserve life index (years):		
Proved	7.4	7.3
Proved and probable	9.4	9.2
Finding, development and acquisition costs – proved and probable ($/boe):		
Including changes in future development expenditures	19.11	15.91
Excluding changes in future development expenditures	15.50	14.94
Recycle ratio – proved and probable: (7)		
Including changes in future development expenditures	1.9	1.8
Excluding changes in future development expenditures	2.3	1.9

Trust Unit Trading Statistics

($ per unit, except volume)	Three months ended December 31, 2008	September 30, 2008	June 30, 2008	March 31, 2008
High	26.39	37.65	37.64	31.35
Low	14.25	25.01	28.96	24.24
Close	17.00	26.29	37.45	29.85
Average Daily Volume - Units	425,042	273,074	329,638	231,949

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) Long-term debt, net of adjusted working capital excludes unrealized gains or losses on financial instruments and its related tax impact.

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

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

(6) Operating netback equals production revenues including realized gains or losses on financial instruments, less royalties, transportation and operating expenses, calculated on a boe basis.

(7) Recycle ratio is calculated using operating netback per boe divided by finding, development and acquisition costs per boe.

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, 2008. Bonavista has continued on its course of generating profitable results since commencing operations as an energy trust in July 2003. The results of 2008 are highlighted with strong operational and financial results derived from the success in our capital programs during the year. The continued execution of Bonavista's proven strategies in 2008 and for the future are a testament to the validity and effectiveness of an operationally and technically focused energy trust. During these times of global uncertainty and volatility, these strategies enable Bonavista to be nimble, flexible and responsive to our changing environment. Bonavista remains consistently focused on the key aspects of our business through optimizing production and revenues, reducing the costs of our business, improving reinvestment efficiency and adjusting our capital programs and distribution policy to maximize value to our unitholders. Due to the current economic conditions and continued weak commodity prices, Bonavista has reduced its capital spending projections for 2009 to between $225 and $250 million. This level of spending will result in the drilling of approximately 100 to 115 wells, and result in production averaging between 51,500 and 52,500 boe per day. In addition, effective for our March 2009 production for which distributions are payable on April 15, 2009, Bonavista is reducing its monthly distribution to unitholders by $0.04 per unit to $0.16 per unit. Although this revised level of capital spending is down over 50% from 2008 and our distributions will be reduced by 20%, we believe this to be prudent given the uncertainty surrounding the prevailing economy. Maintaining our healthy financial position, along with our low costs, and our capital spending flexibility, positions Bonavista very well to sustain a longer term downturn and allows us to remain poised to pursue incremental opportunities as they arise.

Accomplishments for Bonavista in 2008 include:

- Operationally, production volumes averaged 53,190 boe per day during 2008, a record level, versus 52,505 boe per day in 2007 and have increased 54% from 34,600 boe per day since commencement as an energy trust on July 2, 2003. Bonavista's current production rate is approximately 53,000 boe per day;
- Added 31.1 mmboe of proved and probable reserves during 2008, which replaced annual production by 1.6 times and improved the Trust's proved and probable reserve life index to 9.4 years from 9.2 years in 2007. These reserves were added at a finding, development and acquisition cost, including changes in future development expenditures, of $22.10 per boe on a proved basis ($18.06 per boe excluding changes in future development expenditures) and $19.11 per boe on a proved and probable basis ($15.50 per boe excluding changes in future development expenditures). A proved and probable recycle ratio of 1.9:1 (1.6:1 proved) was achieved in 2008 as a result of this level of finding, development and acquisition costs. Overall in 2008, Bonavista increased proved and probable reserves by 6% to 191.1 mmboe while spending 75% of funds from operations on exploitation, development and acquisition expenditures;
- Maintained an active capital program in 2008 investing $305.5 million in exploitation and development activities. Bonavista drilled 200 wells with an overall 95% success rate, and we spent an additional $176.8 million on 20 synergistic acquisitions within our core regions;
- Drilled 24 successful horizontal wells on the highly prospective, light oil Bakken trend in our Southeast Saskatchewan area resulting in production reaching 1,300 bbls per day. In addition to our Bakken resource initiatives, we have identified additional resource plays to pursue in the coming months using horizontal drilling and multi-stage fracture stimulation technology;
- On January 14, 2008 Bonavista completed the $172.2 million acquisition of producing and undeveloped oil and natural gas properties (61% natural gas weighted) in the greater Willesden Green area. This acquisition further complemented the property acquisition that we completed in the fourth quarter of 2007 and our pre-existing assets in this area where we have recently experienced tremendous success utilizing the latest horizontal, multi-stage fracture technology. We now have a concentrated position in this area with current production of approximately 6,500 boe per day and numerous, low cost exploitation and optimization opportunities to pursue in the future;
- Continued to actively participate at crown land sales and freehold purchases, investing $26.2 million in land activity, further enhancing our future drilling prospect inventory for several years. Bonavista now holds approximately 1.1 million net acres of undeveloped land within its four core regions;
- Generated record funds from operations of $643.9 million ($5.64 per unit) for the year ended December 31, 2008 and $131.7 million ($1.12 per unit) in the fourth quarter of 2008. Of the total funds from operations generated in the respective periods, Bonavista distributed 52% of these funds for the year ended December 31, 2008 and 65% of these funds in the fourth quarter to Unitholders with the remaining funds reinvested in the business to continue growing our production base;
- Continued to record strong profitability for the year ended December 31, 2008 with a strong return on equity of 23% and a strong net income to funds from operations ratio of 43%. The above ratios reflect net income adjusted to negate the after tax impact of the unrealized gains and losses on financial instruments;
- Since inception as a Trust, Bonavista has delivered cumulative distributions of $1.5 billion or $19.11 per trust unit. These cumulative distributions are in excess of our closing price of $16.00 per trust unit on the first trading day after we became an energy trust on July 2, 2003;

- On April 29, 2008 Bonavista completed a $214.0 million equity financing, improving financial flexibility to pursue future growth opportunities through expansions in either our exploitation and development activities or acquisition programs. The ratio of 2008 year-end debt, net of adjusted working capital to fourth quarter of 2008 annualized funds from operations is 1.2:1, which is very attractive in our industry; and
- On August 25, 2008, Bonavista extended the term of its covenant-based $1.0 billion syndicated bank loan facility to August 10, 2011.

Strengths of Bonavista Energy Trust

Upon restructuring from an exploration and production corporation into an energy trust in July 2003, Bonavista brought forward all of the same attributes that resulted in the tremendous success of the company between 1997 and 2003. We have maintained a high level of investment activity on our asset base, increasing production more than 50% since 2003. This activity stems from the operational and technical focus of our Trust, the attention to detail, and the ability to generate economic prospects on our asset base within the Western Canadian Sedimentary Basin. Our experienced and consistent technical teams have a solid understanding of our assets 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, an increase in the quality and quantity of our drilling inventory and a growing production base. Our production base is balanced 55% in favour of natural gas and 45% towards oil and liquids and is geographically focused within select medium depth, multi-zone regions in Alberta, Saskatchewan and British Columbia. This asset base has a low operating cost structure resulting in attractive operating netbacks. 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.

Our team brings a successful track record of executing low to medium risk development programs, including both asset and corporate acquisitions, along with a record of 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. Our management team and Board of Directors possess extensive experience in the oil and natural gas business, navigating successfully through many different economic cycles utilizing a proven strategy consisting of strict cost controls and prudent financial management. Directors, management and employees also own approximately 17% of the Trust, resulting in a close 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, 2008. The following MD&A of the financial condition and results of operations was prepared at, and is dated March 2, 2009 and incorporates by reference the Trust's fourth interim report and press release dated March 2, 2009. Our audited consolidated financial statements, Annual Report, and other disclosure documents for 2008 will be available on or before March 31, 2009 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 including; (i) forecasted capital expenditures; (ii) exploration, drilling and development plans; (iii) anticipated production rates; (iv) expected royalty rate; (v) annualized debt to funds from operations; (vi) funds from operations, (vii) anticipated operating costs; (viii) expected service agreement fees; (ix) interest expense per boe; and (x) drilling prospects, which are provided to allow investors to better understand our business. 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 there from. 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 an 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, 2008 led to the drilling of 200 wells in our four core regions with an overall success rate of 95%. This program resulted in 84 natural gas wells, 106 oil wells and 10 dry holes. Bonavista continues to pursue deeper and higher impact drilling opportunities particularly in the Lower Mannville sands in our Central region in Alberta and in the Bakken play in our Southeast Saskatchewan area, where we have experienced excellent success and attractive finding and development costs over the past few years. These activities have also continued to lengthen our reserve life index and the predictability in our overall production base. In addition to the exploitation and development program, Bonavista executed 20 complementary acquisitions in its core regions during 2008.

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, 84% were evaluated by independent third party engineers, GLJ Petroleum Consultants Ltd. ("GLJ") and Ryder Scott Company Canada in their reports dated February 24, 2009 depending on the location of the property. The balance of approximately 16% of proved and probable net present value reserves were evaluated internally and reviewed by GLJ. The reserve estimates contained in the following tables represent Bonavista's interest reserves before the deduction of royalties:

		Oil and	Total	Net Present Value @		
	Natural Gas	**Liquids**	**Reserves**	**0%**	**5%**	**10%**
	(bcf)	(mbbls)	(mboe)		(millions)	
Proved:						
Proved producing	376.8	49,802	112,596	$ 4,133	$ 2,945	$ 2,320
Proved non-producing	33.5	4,500	10,088	304	226	178
Proved undeveloped	52.3	10,742	19,466	794	474	319
Total proved (1)	462.6	65,044	142,150	5,231	3,645	2,818
Probable	151.0	23,775	48,945	2,234	1,159	737
Total proved and probable (1)	**613.7**	**88,817**	**191,095**	**$ 7,465**	**$ 4,804**	**$ 3,555**

	Natural Gas	Oil and Liquids	Total Reserves
	(bcf)	(mbbls)	(mboe)
Proved:			
December 31, 2007	427.1	63,724	134,911
Exploitation and development	58.3	8,219	17,939
Revisions (2)	14.2	(964)	1,399
Acquisitions, net	26.9	2,878	7,369
Production	(63.9)	(8,813)	(19,468)
December 31, 2008 (1)	**462.6**	**65,044**	**142,150**
Proved and probable:			
December 31, 2007	561.0	85,955	179,454
Exploitation and development	74.4	11,508	23,916
Revisions (2)	4.2	(3,906)	(3,211)
Acquisitions, net	38.0	4,073	10,404
Production	(63.9)	(8,813)	(19,468)
December 31, 2008 (1)	**613.7**	**88,817**	**191,095**

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

Bonavista's 2008 year-end proved reserves totalled 142.2 mmboe, a 5% increase compared to the 134.9 mmboe at the year-end of 2007. Furthermore, Bonavista's proved and probable reserves increased by 6% to 191.1 mmboe when compared to the 179.5 mmboe at year-end 2007. Bonavista's proved and probable reserve life index ("RLI") also increased during the year to 9.4 years, with the proved RLI at 7.4 years. Finding, development and acquisition costs in 2008, including changes in future capital expenditures, amounted to $22.10 per boe ($18.06 per boe before changes in future capital expenditures) on a proved basis and $19.11 per boe ($15.50 per boe before changes in future capital expenditures) on a proved and probable basis. The Trust had negative proved plus probable reserve revisions of 3.2 mmboe which were primarily related to performance issues at four heavy oil properties, a reassessment of waterflood performance at one of our light oil properties and revisions to a couple of properties in British Columbia. The aggregate of the exploitation 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 1.9:1 for proved and probable reserves and 1.6:1 for proved reserves which includes revisions and changes in future development expenditures; excluding changes in future development expenditures, the proved and probable recycle ratio increased to 2.3:1 and the proved recycle ratio increased to 2.0:1. Additional reserves disclosure tables, as required under NI 51-101, are contained in Bonavista's Annual Information Form that will be filed on SEDAR.

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,	
	2008	**2007**	**2008**	**2007**
($ thousands, except per boe/Trust Unit Amounts and where noted)				
Product prices:				
Natural gas ($/mcf)	7.52	6.74	8.30	6.95
Oil and liquids ($/bbl)	53.05	58.04	70.68	54.40
Production:				
Natural gas (mmcf/d)	171	170	175	171
Oil and liquids (bbls/d)	24,733	24,775	24,079	24,034
Total production (boe/d)	53,288	53,029	53,190	52,505
Production revenues	221,782	242,361	1,234,391	911,346
per boe	45.24	49.68	63.41	47.55
Royalties	39,801	42,809	239,967	155,586
per boe	8.12	8.77	12.33	8.12
% of Production revenues	17.9%	17.7%	19.4%	17.1%
Operating expenses	48,603	41,867	184,053	162,371
per boe	9.91	8.58	9.45	8.47
Transportation expenses	9,589	10,364	38,744	41,397
per boe	1.96	2.12	1.99	2.16
General and administrative expenses	3,825	3,620	14,410	13,335
per boe	0.78	0.74	0.74	0.70
Financing expenses	5,761	10,915	32,535	35,209
per boe	1.18	2.24	1.67	1.84
Funds from operations	131,741	127,778	643,876	502,783
per boe	26.87	26.19	33.07	26.24
per unit – basic	1.12	1.20	5.64	4.76
Unit-based compensation	4,694	2,809	11,049	7,351
per boe	0.96	0.58	0.57	0.38
Depreciation, depletion and accretion	69,000	60,659	266,271	232,722
per boe	14.07	12.43	13.68	12.14
Income taxes (reduction)	23,324	(30,831)	49,451	(535)
per boe	4.76	(6.32)	2.54	(0.03)
Net income	129,192	63,631	438,366	218,187
per boe	26.35	13.04	22.52	11.39
per unit – basic	1.09	0.60	3.84	2.07
Distributions declared	85,824	77,136	332,540	307,401
per unit	0.90	0.90	3.60	3.60

Production - For the year ended December 31, 2008, production increased 1% to 53,190 boe per day when compared to 52,505 boe per day for the same period a year ago. Specifically, average natural gas production increased 2% to 175 mmcf per day in 2008 from 171 mmcf per day for the same period a year ago, while total oil and liquids production increased slightly to 24,079 bbls per day in 2008 (comprised of 17,440 bbls per day of light and medium oil and 6,639 bbls per day of heavy oil) from 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) for the same period in 2007. For the fourth quarter of 2008, production increased slightly to 53,288 boe per day when compared to 53,029 boe per day for the same period in 2007. Natural gas production remained relatively unchanged at 171 mmcf per day in the fourth quarter of 2008 from 170 mmcf per day for the same period a year ago, while total oil and liquids production decreased marginally to 24,733 bbls per day in the fourth quarter of 2008 (comprised of 18,120 bbls per day of light and medium oil and 6,613 bbls per day of heavy oil) from 24,775 bbls per day (comprised of 16,825 bbls per day of light and medium oil and 7,950 bbls per day of heavy oil) for the same period in 2007. Both oil and natural gas volumes were adversely impacted by approximately 900 boe per day in the quarter due to unusually cold weather in December and weaker heavy oil prices resulting in some heavy oil production being shut in. This being said, Bonavista's diversified commodity investment approach minimizes our dependence on any one product. We anticipate production volumes in 2009 to average between 51,500 and 52,500 boe per day. Our current production is approximately 53,000 boe per day consisting of 55% natural gas, 34% light and medium oil and 11% heavy oil.

Production revenues - Production revenues for the year ended December 31, 2008 increased by 35% to $1,234.4 million when compared to $911.3 million for the same period a year ago, primarily due to higher average commodity prices. For the year ended December 31, 2008, natural gas prices increased 19% to $8.30 per mcf, when compared to $6.95 per mcf realized in the same period in 2007. The average oil and liquids price also increased 30% to $70.68 per bbl (comprised of $71.70 per bbl for light and medium oil and $68.01 per bbl for heavy oil) for the year ended December 31, 2008 from $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 same period in 2007. Production revenues, for the fourth quarter of 2008 decreased by 8% to $221.8 million when compared to $242.4 million for the same period a year ago due to lower average oil and liquids prices offset somewhat by higher natural gas prices. In the fourth quarter of 2008, natural gas prices increased 12% to $7.52 per mcf, compared to $6.74 per mcf realized in the same period in 2007, although the average oil and liquids price decreased 9% to $53.05 per bbl (comprised of $52.90 per bbl for light and medium oil and $53.47 per bbl for heavy oil) in the fourth quarter of 2008 from $58.04 per bbl (comprised of $62.32 per bbl for light and medium oil and $48.99 per bbl for heavy oil) for the same period in 2007.

The following table highlights Bonavista's realized commodity pricing for the three months and year ended December 31:

	Three months ended December 31,		**Years ended December 31,**	
	2008	**2007**	**2008**	**2007**
Natural gas ($/mcf):				
Production revenues	$ 7.30	$ 6.63	$ 8.29	$ 6.87
Realized gains (losses) on financial instruments	0.22	0.11	0.01	0.08
	7.52	6.74	8.30	6.95
Light and medium oil ($/bbl):				
Production revenues	48.06	66.98	81.40	59.70
Realized gains (losses) on financial instruments	4.84	(4.66)	(9.70)	(1.09)
	52.90	62.32	71.70	58.61
Heavy oil ($/bbl):				
Production revenues	43.76	48.24	76.08	44.93
Realized gains (losses) on financial instruments	9.71	0.75	(8.07)	0.27
	$ 53.47	$ 48.99	$ 68.01	$ 45.20

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 volatile 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 primarily using costless collars limits Bonavista's exposure to downturns in commodity prices, while allowing for participation in commodity price increases. For the year ended December 31, 2008, our risk management program on financial instruments resulted in a net gain of $40.5 million, consisting of a realized loss of $80.8 million and an unrealized gain of $121.3 million. The realized loss of $80.8 million consisted of a $744,000 gain on natural gas commodity derivative contracts and an $81.5 million loss on crude oil commodity derivative contracts. For the same period in 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, 2008, our risk management program on financial instruments resulted in a net gain of $112.0 million consisting of a realized gain of $17.5 million and an unrealized gain of $94.5 million. The realized gain of $17.5 million consisted of a $3.6 million gain on natural gas commodity derivative contracts and a $13.9 million gain on crude oil commodity derivative contracts. For the similar period in 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.

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for crude oil and natural gas are impacted not only by global economic events that dictate the levels of supply and demand but also by the relationship between the Canadian and United States dollar. The Trust has attempted to mitigate a portion of the commodity price risk through the use of various financial instruments and physical delivery sales contracts. The Trust's policy is to enter into commodity price contracts when considered appropriate to a maximum of 60% of net after royalty, forecasted production volumes.

i) Financial instruments:

As at December 31, 2008, the Trust has hedged by way of costless collars to sell natural gas and crude oil as follows:

Volume	Average Price			Term
10,000 gjs/d	CDN$ 9.25	-	CDN$ 13.50 – AECO	January 1, 2009 – March 31, 2009
10,000 gjs/d	CDN$ 7.50	-	CDN$ 9.50 – AECO	April 1, 2009 – October 31, 2009
5,000 mmbtu/d	US$ 6.81	-	US$ 7.91 – AECO	January 1, 2009 – March 31, 2009
1,000 bbls/d	CDN$ 70.00	-	CDN$ 78.00 – Bow River	January 1, 2009 – December 31, 2009
3,000 bbls/d	CDN$ 81.67	-	CDN$ 121.33 – WTI	January 1, 2009 – December 31, 2009
2,000 bbls/d	US$ 65.00	-	US$ 80.50 – WTI	January 1, 2009 – March 31, 2009
1,000 bbls/d	US$ 85.00	-	US$ 105.60 – WTI	January 1, 2009 – December 31, 2009
2,000 bbls/d	CDN$ 105.00	-	CDN$ 169.00 – WTI	April 1, 2009 – December 31, 2009

Financial instruments are recorded on the consolidated balance sheet at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the consolidated statements of operations, comprehensive income and accumulated earnings. As at December 31, 2008 the fair market value recorded on the consolidated balance sheet for these financial instruments was an asset of $76.2 million, compared to a liability of $45.1 million in 2007. These financial instruments had the following gains and losses reflected in the consolidated statements of operations, comprehensive income and accumulated earnings:

	Years ended December 31, 2008	Years ended December 31, 2007
Realized gains (losses) on financial instruments	$ (80,806)	$ (665)
Unrealized gains (losses) on financial instruments	121,261	(45,058)
	$ 40,455	$ (45,723)

Bonavista mitigates its risk associated with fluctuations in commodity prices by utilizing financial instruments. A $0.10 increase or a $0.10 decrease to the price per thousand cubic feet of natural gas – AECO would have an impact of approximately $5.2 million and $5.4 million respectively, on net income for those financial instruments that were in place as at December 31, 2008. A $1.00 increase or a $1.00 decrease to the price per barrel of oil - WTI would have an impact of approximately of $5.1 million and $2.6 million respectively, on net income for those financial instruments that were in place as at December 31, 2008.

ii) Physical purchase contracts:

As at December 31, 2008, the Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume	Average Price (CDN$ - AECO)	Term
40,000 gjs/d	$ 8.16 - $ 10.69	January 1, 2009 – March 31, 2009
10,000 gjs/d	$ 8.00 - $ 10.84	April 1, 2009 – October 31, 2009

Physical purchase contracts are being accounted for as they are settled.

Royalties - For the year ended December 31, 2008, royalties increased 54% to $240.0 million from $155.6 million for the same period a year ago, largely attributed to an increase in commodity prices and increased heavy oil royalties resulting from the payout of two oilsands royalty projects. In addition, royalties as a percentage of revenues (including realized gains and losses on financial instruments) for 2008 increased to 20.8% compared to 17.1% in 2007 for similar reasons discussed above and the impact of realized losses on financial instruments. For the year ended December 31, 2008, royalties by product as a percentage of revenues (including realized gains and losses on financial instruments) were 21.9% for natural gas, 19.3% for light and medium oil and 21.4% for heavy oil. For the year ended December 31, 2007, royalties by product as a percentage of revenues (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 three months ended December 31, 2008, royalties decreased by 7% to $39.8 million from $42.8 million for the same period a year ago largely due to declining oil and liquids prices. In addition, royalties as a percentage of revenues (including realized gains and losses on financial instruments) for the fourth quarter of 2008 decreased from 18.0% in 2007 to 16.6%, for the same reasons as discussed above and the impact of realized gains on financial instruments. For the three months ended December 31, 2008, royalties by product as a percentage of revenues (including realized gains and losses on financial instruments) were 19.9% for natural gas, 12.8% for light and medium oil and 15.2% for heavy oil. 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.

On October 25, 2007, the Alberta Government announced the New Royalty Framework ("NRF") which was subsequently revised on April 10, 2008 to provide further clarification on the NRF as well as to introduce two new royalty programs related to the development of deep oil and natural gas reserves. The NRF was legislated in November 2008 and took effect on January 1, 2009. Subsequent to legislation of the NRF, the Government of Alberta introduced the Transitional Royalty Plan ("TRP") in response to the decrease in development activity in Alberta resulting from declining commodity prices and the global economic downturn. The TRP offers reduced royalty rates for new wells drilled on or after November 19, 2008 that meet certain depth requirements. An election must be filed on an individual well basis in order to qualify for the TRP. The TRP is in place for a maximum of 5 years to December 31, 2013. All wells drilled between 2009 and 2013 that adopt the transitional rates will be required to shift to the NRF on January 1, 2014. The Trust does not anticipate a significant benefit in 2009 given that its current wells converted to the NRF effective January 1, 2009. The Trust has reviewed the NRF and has determined that its impact will change the Trust's corporate forecast royalty rate over the life of the reserves by less than 1% as compared to the royalty rates that would have been calculated with the royalty regime in place during 2008 based on benchmark pricing as at December 31, 2008.

Operating expenses - Operating expenses for the year ended December 31, 2008 increased 13% to $184.1 million compared to $162.4 million for the same period a year ago. Operating expenses for the fourth quarter of 2008 increased 16% to $48.6 million compared to $41.9 million for the same period a year ago. Operating expenses increased due to the continuation of industry wide operating cost pressures, primarily driven by higher fuel, power, trucking, chemical and labour costs. These factors resulted in average per unit operating expenses increasing by 12% to $9.45 per boe for the year ended December 31, 2008, from $8.47 per boe in the comparable period of 2007. For 2008, operating expenses by product were $1.35 per mcf for natural gas, $10.07 per bbl for light and medium oil and $13.69 per bbl for heavy oil compared to $1.17 per mcf for natural gas, $9.16 per bbl for light and medium oil and $12.36 per bbl for heavy oil for the same period in 2007. For the three months ended December 31, 2008, operating expenses per boe increased 16% to $9.91 per boe from $8.58 per boe in the comparable period of 2007. Operating expenses by product for the fourth quarter of 2008 were $1.44 per mcf for natural gas, $10.38 per bbl for light and medium oil and $14.07 per bbl for heavy oil compared to $1.16 per mcf for natural gas, $9.31 per bbl for light and medium oil and $12.72 per bbl for heavy oil for the same period in 2007. Notwithstanding these cost increases, Bonavista continues to experience one of the lowest operating costs of any producer in the energy trust sector and remains optimistic that the recent upward trend in operating costs will reverse in 2009.

Transportation expenses - For the year ended December 31, 2008, transportation expenses decreased 6% to $38.7 million ($1.99 per boe) when compared to $41.4 million ($2.16 per boe) for 2007. The 8% decrease in transportation expenses on a per boe basis was primarily due to a decrease in natural gas transportation costs because of the expiry of certain firm export service obligations offset by slightly higher trucking costs for our oil and liquids. For similar reasons, transportation costs for the three months ended December 31, 2008 decreased 7% to $9.6 million ($1.96 per boe) compared to $10.4 million ($2.12 per boe) for the same period a year ago. Transportation expenses by product for the year ended December 31, 2008 were $0.38 per mcf for natural gas, $0.85 per bbl for light and medium oil and $3.64 per bbl for heavy oil compared to $0.44 per mcf for natural gas, $0.92 per bbl for light and medium oil and $3.18 per bbl for heavy oil for the same period in 2007. For the fourth quarter of 2008 transportation expenses by product were $0.36 per mcf for natural gas, $0.86 per bbl for light and medium oil and $4.05 per bbl for heavy oil compared to $0.43 per mcf for natural gas, $0.86 per bbl for light and medium oil and $3.19 per bbl for heavy oil for the same period a year ago.

General and administrative expenses - General and administrative expenses, after overhead recoveries, increased 8% to $14.4 million for the year ended December 31, 2008 from $13.3 million in the same period in 2007 and increased 6% to $3.8 million for the three months ended December 31, 2008 from $3.6 million in the same period in 2007. On a per boe basis, general and administrative expenses increased 6% for the year ended December 31, 2008 to $0.74 per boe from $0.70 per boe in the same period in 2007 and increased 5% for the three months ended December 31, 2008 to $0.78 per boe from $0.74 per boe in the same period in 2007. These increases are largely due to the higher costs of personnel required to manage our operations and increasing cost pressures currently experienced throughout our industry.

In addition, through the services agreement with NuVista Energy Ltd., ("NuVista") Bonavista provides certain administrative activities. The fee charged under this agreement was $1.1 million for the year ended December 31, 2008 as compared to $1.4 million in the same period in 2007 and $26,000 for the three months ended December 31, 2008 as compared to $400,000 for the same period in 2007. The fees charged to NuVista through the services agreement was terminated effective November 1, 2008.

In connection with its Trust Unit Incentive Rights and Restricted Trust Unit Plans, Bonavista recorded a unit-based compensation charge of $11.0 million and $4.7 million for the year and three months ended December 31, 2008 respectively, compared to $7.4 million and $2.8 million for the same periods in 2007.

Financing expenses - Financing expenses, which include interest expense on long-term debt and convertible debentures, decreased 8% to $32.5 million for the year ended December 31, 2008, from $35.2 million for the same period in 2007 and on a boe basis, decreased 9% to $1.67 per boe for the year ended December 31, 2008 from

$1.84 per boe for the same period in 2007. This decrease is due to lower average debt levels used to fund Bonavista's capital program, proceeds received from a $214.0 million equity financing and a declining interest rate environment. For the three months ended December 31, 2008, financing expenses decreased 47% to $5.8 million from $10.9 million for the same period in 2007 and on a boe basis decreased 47% to $1.18 per boe for the three months ended December 31, 2008 from $2.24 per boe in the same period in 2007 for similar reasons as discussed above. For the year ended December 31, 2008, Bonavista paid cash interest of $32.9 million compared to $35.4 million for the same period in 2007. During the fourth quarter of 2008, Bonavista paid cash interest of $6.4 million compared to $11.3 million in 2007. Bonavista's effective interest rate as at December 31, 2008 was approximately 2% (2007 – 5%).

Depreciation, depletion and accretion expenses - Depreciation, depletion and accretion expenses increased 14% to $266.3 million for the year ended December 31, 2008 from $232.7 million for the same period of 2007. For the three months ended December 31, 2008 depreciation, depletion and accretion expenses also increased 14% to $69.0 million from $60.7 million in the same period in 2007. Both increases were due to higher costs of finding, developing and acquiring reserves and a larger asset base in 2008. For the year ended December 31, 2008, the average cost increased to $13.68 per boe from $12.14 per boe for the same period in 2007 and for the three months ended December 31, 2008 the average cost increased to $14.07 per boe from $12.43 per boe for the same period a year ago. The increase in depreciation, depletion and accretion expenses is due to increased costs associated with adding new reserves. Over the past few years our industry has seen cost escalation in all areas of our activities.

Income taxes - For the year ended December 31, 2008, the provision for income tax was $49.5 million compared to a recovery of $535,000 for the same period in 2007. For the three months ended December 31, 2008, the provision for income tax was $23.3 million compared to a recovery of $30.8 million for the same period in 2007. Bonavista made no cash payments relating to installments for either of the year ended and three months ended December 31, 2008, or for the comparative periods in 2007.

On February 26, 2008, the Federal government announced that the provincial component of the SIFT tax is to be determined based on the general corporate provincial tax rate in each province that the Trust has a permanent establishment. On June 18, 2008, the legislation to re-define the provincial component of the tax rate was passed. The specific rules governing how the provincial component is to be calculated was released in draft on July 14, 2008, however, it is not considered to be substantively enacted as at December 31, 2008. As a result, any changes in the tax rate for the Trust's future income tax has not been reflected in the Trust's consolidated financial statements.

Funds from operations, net income and comprehensive income - For the year ended December 31, 2008, Bonavista experienced a 28% increase in funds from operations to $643.9 million ($5.64 per unit, basic) from $502.8 million ($4.76 per unit, basic) for the same period in 2007, primarily due to higher commodity prices. For the three months ended December 31, 2008, Bonavista experienced a 3% increase in funds from operations to $131.7 million ($1.12 per unit, basic) from $127.8 million ($1.20 per unit, basic) for the same period in 2007, primarily due to the impact of realized gains on financial instruments as they offset declining oil and liquids pricing. Net income for the year ended December 31, 2008, increased 101% to $438.4 million ($3.84 per unit, basic) from $218.2 million ($2.07 per unit, basic) for the same period in 2007. For the three months ended December 31, 2008, net income increased 103% to $129.2 million ($1.09 per unit, basic) from $63.6 million ($0.60 per unit, basic) for the same period in 2007. Other comprehensive income for the year ended December 31, 2008 included a charge of nil (2007 - $6.0 million) 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 a total comprehensive income for the year ended December 31, 2008 of $438.4 million (2007 – $212.2 million). Other comprehensive income for the three months ended December 31, 2008 included a charge of nil (2007 – $2.5 million) 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, 2008 of $129.2 million (2007 – $61.1 million).

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

	Three months ended December 31,		**Years ended December 31,**	
Calculation of Funds From Operations:	**2008**	**2007**	**2008**	**2007**
(thousands)				
Cash flow from operating activities	$ 141,448	$ 95,459	$ 678,228	$ 473,021
Asset retirement expenditures	5,061	4,784	15,229	8,338
Changes in non-cash working capital	(14,768)	27,535	(49,581)	21,424
Funds from operations	$ 131,741	$ 127,778	$ 643,876	$ 502,783

Capital expenditures - Capital expenditures for the year ended December 31, 2008 were $482.3 million, consisting of $305.5 million on exploitation and development spending and $176.8 million on net property acquisitions. For the same period in 2007 capital expenditures were $366.4 million, consisting of $267.7 million on exploitation and development spending and $98.7 million on net property acquisitions. Capital expenditures for the three month period ended December 31, 2008 were $60.1 million, consisting of $60.2 million on exploitation and development spending and $105,000 on net property dispositions. For the same period in 2007 capital expenditures were $58.0 million, consisting of $58.4 million on exploitation and development spending and $425,000 on net property dispositions. Our consistent exploitation and development program continues to generate predictable and attractive re-investment efficiencies despite the current high cost environment.

The following table outlines capital expenditures by category for the years ended December 31, 2008 and 2007:

	Years ended December 31, 2008	2007
(thousands)		
Land acquisitions	$ 26,165	$ 33,211
Geological and geophysical	10,687	9,811
Drilling and completion	176,361	139,578
Production equipment and facilities	91,138	84,444
Other	1,163	616
Exploitation and development expenditures	305,514	267,660
Acquisitions	187,023	100,806
Dispositions	(10,240)	(2,110)
Net capital expenditures	**$ 482,297**	**$ 366,356**

Liquidity and capital resources - As at December 31, 2008, long-term debt including working capital (excluding unrealized gains on financial instruments and related tax impact) was $654.5 million with a debt to 2008 annualized fourth quarter funds from operations ratio of 1.2:1. Bonavista has significant flexibility to finance future expansions of its capital programs or acquisition opportunities as they arise, through the use of its bank loan facility of $1.0 billion of which $345.5 million is unused borrowing capability and the use of its funds from operations, or through a combination of both bank debt and funds from operations.

Bonavista's bank loan facility is provided by a syndicate of 12 domestic and international banks. The bank loan facility is a three year revolving facility and may at the request of the Trust and with the consent of the lenders be extended on an annual basis. On August 25, 2008, Bonavista and its lenders agreed to extend its bank loan facility to August 10, 2011 with no principal repayments required until then. This facility also includes an accordion feature providing that at any time during the term, on participation of any existing or additional lenders, we can increase the facility by $250 million.

Under the terms of the credit facility, the Trust has provided the covenant that its: (i) consolidated senior debt borrowing will not exceed three times net income before unrealized gains and losses on financial instruments, interest, taxes and depreciation, depletion and accretion; (ii) consolidated total debt will not exceed three and one half times consolidated net income before unrealized gains and losses on financial instruments, interest, taxes and depreciation, depletion and accretion; and (iii) consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated unitholders' equity of the Trust, in all cases calculated based on a rolling prior four quarters.

In 2009, Bonavista plans to invest between $225 and $250 million on its capital programs to expand its core regions. Given the current global economic weakness and the constraints in both the equity and credit environments, the Trust along with all other oil and gas entities have restricted access to capital and potentially increased borrowing costs. The Trust intends on financing its 2009 capital program with a combination of funds from operations and to the extent required, its existing credit facility. The Trust is committed to the fundamental principle of maintaining financial flexibility and the prudent use of debt, as such, our 2009 capital program is based upon using a conservative amount of debt in our financing structure.

Unitholders' equity - As at December 31, 2008, Bonavista had 118.1 million equivalent trust units outstanding. This includes 11.4 million exchangeable shares, which are exchangeable into 22.3 million trust units. The exchange ratio in effect at December 31, 2008 for exchangeable shares was 1.96225:1. As at March 2, 2009, Bonavista had 118.8 million equivalent trust units outstanding. This includes 10.2 million exchangeable shares, which are exchangeable into 20.6 million trust units. The exchange ratio in effect at March 2, 2009 for exchangeable shares was 2.02089:1. In addition, Bonavista has 4.3 million trust unit incentive rights outstanding at March 2, 2009, with an average exercise price of $22.52 per trust unit.

As at December 31, 2008, Unitholders' equity included $933,000 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 93,401 of these debentures converted into trust units, leaving 6,599 debentures with a principal amount of $6.6 million outstanding as at December 31, 2008. 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, 2008 there have been 96,433 of these debentures converted into trust units, leaving 38,567 debentures outstanding with a principal amount of $38.6 million.

Contractual obligations - The following is a summary of the Trust's contractual obligations and commitments as at December 31, 2008:

	Payments Due by Period					
	Total	**2009**	**2010**	**2011**	**2012**	**2013 and thereafter**
(thousands)						
Long-term debt repayments [1]	$ 588,792	$ -	$ -	$ 588,792	$ -	$ -
Convertible debentures [2]	45,166	6,599	38,567	-	-	-
Transportation expenses	32,987	11,160	5,653	4,054	3,159	8,961
Office premises	3,235	1,527	1,412	296	-	-
Total contractual obligations	**$ 670,180**	**$ 19,286**	**$ 45,632**	**$ 593,142**	**$ 3,159**	**$ 8,961**

(1) Based on the existing terms of the revolving credit facility, the amounts owing under this facility are required to be paid in 2011. However, it is expected that the revolving credit facility will be extended and no repayments will be required in the near term.

(2) The Trust may at its option redeem the principal amount of, and premiums (if any) on the Debentures that have matured by either the issuance of trust units or the cash equivalent to the holders of the Debentures.

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, 2008 the Trust declared distributions of $332.5 million ($3.60 per trust unit) compared to $307.4 million ($3.60 per trust unit) in the same period in 2007. For the three months ended December 31, 2008 the Trust declared distributions of $85.8 million ($0.90 per trust unit) compared to $77.1 million ($0.90 per trust unit) in the same period in 2007. We continuously monitor all the factors influencing our distribution rate and the necessity to adjust the monthly distribution in the future.

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, such as depreciation, depletion and accretion, unrealized gains and losses on financial instruments, fluctuations in future income taxes due to changes in tax rates and tax rules, these non-cash charges do not represent the actual cost of maintaining our production capacity given the natural declines associated with oil and natural gas assets. For the year and three months ended December 31, 2008, the non-cash charges amounted to $205.5 million and $2.5 million respectively compared to $284.6 million and $64.1 million for the same periods in 2007. In 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	**2008**	**2007**	**2008**	**2007**
(thousands)				
Cash flow provided from operating activities	$ 141,448	$ 95,459	$ 678,228	$ 473,021
Net income	129,192	63,631	438,366	218,187
Distributions declared	85,824	77,136	332,540	307,401
Excess of cash flow provided from operating activities over distributions declared	55,624	18,323	345,688	165,620
Excess (shortfall) of net income over distributions declared	43,368	(13,505)	105,826	(89,214)

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 $0.20 per unit, however, due to persistent weak natural gas prices, we are reducing our monthly distribution policy to $0.16 per unit starting for the production month of March 2009 and payable on April 15, 2009. Our long-term objective is to distribute approximately 50% of our funds from operations, which allows us to withhold sufficient funds to finance capital expenditures required to maintain or modestly grow our production base over a longer period of time. Our distribution rate of $0.16 per unit per month starting with March production will place us slightly below this range for 2009, assuming current strip prices are realized.

Annual financial information - The following table highlights selected annual financial information for each of the three years ended December 31, 2008, 2007 and 2006:

Years ended December 31,	**2008**	**2007**	**2006**
(thousands, except per unit amounts)			
Consolidated Statement of Operations Information:			
Production revenues, net of royalties	$ 994,424	$ 755,760	$ 735,176
Funds from operations	643,876	502,783	496,438
Per unit – basic	5.64	4.76	4.86
Per unit – diluted	5.56	4.69	4.74
Net income	438,366	218,187	301,270
Per unit – basic	3.84	2.07	2.95
Per unit – diluted	3.80	2.06	2.90
Consolidated Balance Sheet Information:			
Total capital expenditures	$ 482,297	$ 366,356	$ 316,353
Total assets	2,543,240	2,242,057	2,067,931
Working capital (deficiency)	(11,726)	(10,349)	(6,125)
Long-term debt	588,792	712,654	512,323
Unitholders' equity	1,411,972	1,060,967	1,130,253
Distributions declared	332,540	307,401	324,016

Quarterly financial information - The following table highlights Bonavista's performance for the eight quarterly periods ending on March 31, 2007 to December 31, 2008:

	2008				**2007**			
	December 31	**September 30**	**June 30**	**March 31**	**December 31**	**September 30**	**June 30**	**March 31**
($ thousands, except per unit amounts)								
Production revenues	221,782	354,667	361,555	296,387	242,361	219,885	223,878	225,222
Net income	129,192	207,594	29,282	72,298	63,631	58,990	33,936	61,630
Net income per unit:								
Basic	1.09	1.77	0.26	0.67	0.60	0.56	0.32	0.59
Diluted	1.09	1.75	0.26	0.67	0.59	0.55	0.32	0.59

Production revenues over the past eight quarters has fluctuated between a low of $219.9 million in September 2007 to a high of $361.6 million in June 2008, largely due to the volatility of commodity prices as our volumes have remained relatively constant throughout the last two years. Net income in the past eight quarters has fluctuated from a low of $29.3 million in June 2008 to a high of $207.6 million in September 2008. These fluctuations are primarily influenced by commodity prices, realized and unrealized gains and losses on financial instruments and future income tax recoveries associated with the reduction in corporate income tax rates. Net income increased 103% in the fourth quarter of 2008 as compared to the fourth quarter of 2007. The increase in net income in the fourth quarter of 2008 is attributed to a $112.0 million gain on financial instruments consisting of a $17.5 million realized gain and an unrealized gain of $94.5 million as compared to a $36.5 million loss consisting of a $5.0 million realized loss and an unrealized loss of $31.5 million in the same period in 2007. The large decrease in net income in the second quarter of 2007 is primarily attributable to the non-cash future income tax charge to net income of $41.0 million to reflect 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.

Update on regulatory and financial reporting matters - On August 15, 2008, the Canadian Securities Administrators published its final version of National Instrument 52-109 and is effective for the Trust's 2008 year end reporting. The national instrument includes the certification of the operating effectiveness of internal controls over financial reporting ("ICFR"), requires the use of a control framework to design and evaluate internal controls, provides specific guidance regarding the documentation, testing and evaluation of controls, and provides clarification regarding the definition of material weaknesses and conclusions on disclosure controls and procedures when there is a material weakness in ICFR. Bonavista has concluded that the Trust's internal controls over financial reporting was effective as of December 31, 2008.

On February 13, 2008, 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"). Canadian generally accepted accounting principles as we currently know them, will cease to exist for all publicly reporting entities. Currently, the application of IFRS to the oil and gas industry in Canada requires considerable clarification. The Canadian Securities Administrators are in the process of examining changes to securities rules as a result of this initiative. Bonavista has completed a preliminary analysis of the accounting differences and has plans in place to perform a detailed assessment of the impact of IFRS on our results of operations, financial position and disclosures in 2009.

Effective January 1, 2008, Bonavista adopted Canadian Institute of Chartered Accountants ("CICA") Section 3862, "Financial Instruments – Disclosures", Section 3863, "Financial Instruments – Presentation" and Section 1535, "Capital Disclosure". The first two sections establish standards for the presentation and disclosure of information that enables users to evaluate the significance of financial instruments to the entity's financial position, and the nature and extent of risks arising from financial instruments and how the entity manages the risks. The last section establishes standards for disclosing information about an entity's capital and how it is managed. The Trust will also be required to adopt Section 3064 "Goodwill and Intangible Assets" effective January 1, 2009, which defines the criteria for the recognition of intangible assets.

Environmental matters – On February 19, 2008 the government of British Columbia introduced a consumer-based carbon tax that became effective on July 1, 2008. The Trust is required to pay carbon tax on all fuel used in the province of British Columbia through its normal course of operations. As at December 31, 2008 Bonavista has paid $223,000 with respect to the carbon tax.

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 1 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;
11) counterparty risk with respect to non-performance by counterparties to financial derivative contracts; and
12) financial risk associated with domestic and international debt and equity markets.

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 enter our twelfth year since restructuring the Company in 1997, and our sixth year since converting to an energy trust, we continue to benefit from all of the same qualities that drove the success of Bonavista as a public company and an energy trust. We apply a similar proven strategy and execute this strategy in a disciplined and cost-effective manner much the same as in 1997 when we started on our mission of creating value for our investors. The foundation of this strategy is to actively pursue low to medium risk drilling opportunities on our extensive undeveloped land base within geographically concentrated areas of operations. Despite a very active exploitation and development program over the past few years, the quality and quantity of our drilling opportunities continues to improve as we enter 2009. Bonavista has currently identified approximately 700 drilling prospects on its land base and remains flexible to consider accelerating or decelerating the capital program depending on market conditions. This steady increase in our quality of prospects generated over the past several years 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 and have been successful in strategic acquisition opportunities where we can add value utilizing our own technical expertise. Our timely and prudent approach to capital investments 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 eleven year history.

For 2009, given the current instability of commodity prices and the developments in the global economies stemming from the credit crisis, Bonavista has revised its capital budget to between $225 and $250 million, to be invested in our exploitation, development and acquisition programs. It is anticipated that this level of capital expenditures will result in the drilling of between 100 and 115 wells and production levels to average between 51,500 and 52,500 boe per day, which is a modest decrease compared to 2008. Our development program includes the drilling of 50 high-impact horizontal wells with multi-stage fracs targeted in the Bakken, Glauconite, Viking and Notikewin formations. Bonavista believes that recent new drilling and completion technologies will have a significant impact on our vast land holdings in our core regions and will lead to the development of several resource-type plays. We will closely monitor our capital programs and remain opportunistic to reallocate or expand our capital program on additional property or land acquisitions and/or drilling opportunities as conditions evolve. In the meantime, our conservative approach to spending and distributions will preserve our financial strength and should serve our unitholders well in this uncertain environment.

We are extremely proud of our achievements over the past eleven years and despite some short term commodity weakness, we remain enthusiastic about the future and the growing opportunities that exist for Bonavista. We would like to thank our employees for their significant effort and their continued enthusiasm and perseverance as we pursue these opportunities in this uncertain economic environment. Despite the setbacks we have endured over the past couple of years, such as the passage of federal legislation on the taxation of distributions from certain publicly traded Canadian trusts, the introduction of the New Royalty Framework by the Government of Alberta, and the volatile capital market, Bonavista's commitment and value creation process has not changed. Throughout many business cycles and changes in the business environment, Bonavista has converted adversity into opportunity and has emerged an even stronger entity as a result of this attitude. Our success is based on the consistent application of our core philosophy and operating strategies. Our legal structure may ultimately change by 2011 when the new tax laws become effective, but our steadfast commitment to creating shareholder value will not change in any environment. Our team remains committed to this over the long term, regardless of the changing landscape.

On behalf of the Board of Directors

Keith A. MacPhail
Chairman and Chief Executive Officer

Jason E. Skehar
President and Chief Operating Officer

March 2, 2009
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	Glenn A. Hamilton
Chairman and Chief Executive Officer	Senior Vice President and Chief Financial Officer

March 2, 2009
Calgary, Alberta

AUDITORS' REPORT TO THE UNITHOLDERS

We have audited the consolidated balance sheets of Bonavista Energy Trust as at December 31, 2008 and 2007 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, 2008 and 2007 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 2, 2009

BONAVISTA ENERGY TRUST

Consolidated Balance Sheets

December 31,	**2008**	**2007**
(thousands)		
Assets:		
Current assets:		
Accounts receivable	$ 106,116	$ 112,226
Unrealized gains on financial instruments (note 10)	76,203	-
Future income tax asset (note 9)	-	13,517
	182,319	125,743
Oil and natural gas properties and equipment (note 5)	2,319,600	2,074,993
Goodwill	41,321	41,321
	$ 2,543,240	$ 2,242,057
Liabilities and Unitholders' Equity:		
Current liabilities:		
Accounts payable and accrued liabilities	$ 143,093	$ 65,305
Distributions payable	28,731	25,729
Unrealized losses on financial instruments (note 10)	-	45,058
Future income tax (note 9)	22,221	-
	194,045	136,092
Long-term debt (note 6)	588,792	712,654
Convertible debentures (note 7)	43,711	48,830
Asset retirement obligations (note 4)	127,467	116,893
Future income taxes (note 9)	177,253	166,621
Unitholders' equity:		
Unitholders' capital and debenture conversion component (notes 7 and 8)	1,100,768	851,685
Exchangeable shares (note 8)	69,488	74,710
Contributed surplus (note 8)	10,687	9,369
Accumulated earnings	231,029	125,203
	1,411,972	1,060,967
Commitments (note 12)		
	$ 2,543,240	$ 2,242,057

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,	**2008**	**2007**
(thousands, except per unit amounts)		
Revenues:		
Production	$ 1,234,391	$ 911,346
Royalties	(239,967)	(155,586)
	994,424	755,760
Realized gains (losses) on financial instruments (note 10)	(80,806)	(665)
Unrealized gains (losses) on financial instruments (note 10)	121,261	(45,058)
	1,034,879	710,037
Expenses:		
Operating	184,053	162,371
Transportation	38,744	41,397
General and administrative	14,410	13,335
Financing	32,535	35,209
Unit-based compensation	11,049	7,351
Depreciation, depletion and accretion	266,271	232,722
	547,062	492,385
Income before taxes	487,817	217,652
Income taxes (reductions) (note 9)	49,451	(535)
Net income	438,366	218,187
Changes in comprehensive income, net of taxes	-	(5,994)
Comprehensive income	438,366	212,193
Accumulated earnings, beginning of year	125,203	214,417
Distributions declared	(332,540)	(307,401)
Accumulated earnings, end of year	$ 231,029	$ 125,203
Net income per unit – basic	$ 3.84	$ 2.07
Net income per unit – diluted	$ 3.80	$ 2.06

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY TRUST
Consolidated Statements of Cash Flows

Years ended December 31,	2008	2007
(thousands, except per unit amounts)		
Cash provided by (used in):		
Operating Activities:		
Net income	$ 438,366	$ 218,187
Items not requiring cash from operations:		
Depreciation, depletion and accretion	266,271	232,722
Unit-based compensation	11,049	7,351
Unrealized (gains) losses on financial instruments	(121,261)	45,058
Future income taxes (reductions)	49,451	(535)
Asset retirement expenditures	(15,229)	(8,338)
Changes in non-cash working capital items	49,581	(21,424)
	678,228	473,021
Financing Activities:		
Issuance of equity, net of issue costs	223,152	8,144
Distributions	(329,538)	(307,125)
Changes in long-term debt	(123,862)	200,331
Changes in non-cash working capital items	(344)	(164)
	(230,592)	(98,814)
Investing Activities:		
Exploitation and development	(305,514)	(267,660)
Property acquisitions	(187,023)	(100,806)
Property dispositions	10,240	2,110
Changes in non-cash working capital items	34,661	(7,851)
	(447,636)	(374,207)
Change in cash	-	-
Cash, beginning of year	-	-
Cash, end of year	$ -	$ -

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY TRUST

Notes to Consolidated Financial Statements

Years ended December 31, 2008 and 2007

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 8) 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.

1. 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 judgment. 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 8. 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 8. 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, at the discretion of Trust, the holder will receive for each unit award, including distributions made on the trust units from the date of the grant to and including the vesting date, net of statutory withholding tax, either: (i) equivalent trust units; or (ii) the cash equivalent. 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.

2. Changes in accounting policies:

a) Financial instruments:

On January 1, 2008, the Trust adopted CICA Handbook Section 3862, "Financial Instruments - Disclosures", and Section 3863, "Financial Instruments - Presentation". Section 3862 and 3863 establish standards for the presentation and disclosure of information that enable users to evaluate the significance of financial instruments to the entity's financial position, and the nature and extent of risks arising from financial instruments and how the entity manages these risks. The implementation of these standards did not impact the Trust's financial results, however it did result in additional disclosure presented in note 10 of the Trust's notes to the consolidated financial statements.

b) Capital disclosures:

On January 1, 2008, the Trust adopted CICA Handbook Section 1535 "Capital Disclosures". Section 1535 establishes standards for disclosing information about an entity's capital and how it is managed. This section specifies disclosure about objectives, policies and processes for managing capital, quantitative data about what an entity regards as capital, whether an entity has complied with all capital requirements, and if it has not complied, the consequences of such non-compliances. The implementation of this standard did not impact the Trust's financial results, however it did result in additional disclosure presented in note 11 of the Trust's notes to the consolidated financial statements.

c) Goodwill:

As of January 1, 2009, the Trust will be required to adopt CICA Handbook Section 3064 "Goodwill and Intangible Assets", which defines the criteria for the recognition of intangible assets. This new standard is not expected to have a material impact on the Trust's consolidated financial statements.

d) International Financial Reporting Standards:

On February 13, 2008, Canada's Accounting Standards Board confirmed January 1, 2011 as the effective date for the convergence of Canadian GAAP to International Financial Reporting Standards ("IFRS"). The Canadian Securities Administrators are in the process of examining the changes to securities rules as a result of this initiative. Bonavista has completed a preliminary analysis of the accounting differences and has plans in place to perform a detailed assessment of the impact of IFRS on our results of operations, financial position and disclosures.

3. 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. This new services agreement was subsequently terminated as of November 1, 2008.

For the year ended December 31, 2008 Bonavista charged NuVista $1.1 million (2007 - $1.4 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 (2007 – $1.4 million). For the year ended December 31, 2008, NuVista also credited Bonavista $209,000 (2007 – $618,000) for interest, relating to the cash balance within the jointly owned partnership. As at December 31, 2008, the amount payable to NuVista was $1.2 million, as at December 31, 2007 the amount receivable from NuVista was $703,000.

4. 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. The Trust estimates the total undiscounted amount of expenditures required to settle its asset retirement obligations is approximately $587.0 million (2007 - $540.9 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% (2007 - 7.5%) and an inflation rate of 2% (2007 - 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,	
	2008	**2007**
(thousands)		
Balance, beginning of year	$ 116,893	$ 96,324
Accretion expense	8,577	7,333
Liabilities incurred	9,177	1,629
Liabilities acquired	2,746	3,976
Liabilities settled	(15,229)	(8,338)
Change in assumptions	5,303	15,969
Balance, end of year	**$ 127,467**	**$ 116,893**

5. **Oil and natural gas properties and equipment:**

December 31, 2008		Cost		Accumulated depreciation and depletion		Net book value
(thousands)						
Oil and natural gas properties	$	2,966,957	$	1,174,448	$	1,792,509
Facilities		673,240		149,143		524,097
Office equipment		7,262		4,268		2,994
	$	**3,647,459**	**$**	**1,327,859**	**$**	**2,319,600**

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**

Unproved property costs of $161.8 million as at December 31, 2008 (2007 - $159.3 million) were excluded from the depreciation and depletion calculation. Future development costs of $241.8 million (2007 - $135.2 million) were included in the depreciation and depletion calculation.

Bonavista has calculated the ceiling test as of December 31, 2008. 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, 2008. The benchmark reference prices, as provided by our independent engineering consultants, used in the calculation and adjusted for commodity differentials specific to Bonavista are as follows.

Benchmark Reference Price Forecasts:

Year	WTI Oil (US$/bbl)	AECO Gas (Cdn$/mmbtu)	USD/CAD Exchange Rates
2009	57.50	7.58	0.825
2010	68.00	7.94	0.850
2011	74.00	8.34	0.875
2012	85.00	8.70	0.925
2013	92.01	8.95	0.950
2014	93.85	9.14	0.950
2015	95.73	9.34	0.950
2016	97.64	9.54	0.950
2017	99.59	9.75	0.950
2018	101.59	9.95	0.950
2019	103.62	10.15	0.950
Remainder (1)	2.0%	2.0%	0.950

(1) Escalated at 2% per year thereafter

6. **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. On August 25, 2008 the facility was extended to August 10, 2011 with no principal payments required until then. This facility also includes an accordion feature providing that at anytime during the term, on participation of any existing or additional lenders, we can increase the facility by $250 million.

Under the terms of the credit facility, the Trust has provided the covenant that its: (i) consolidated senior debt borrowing will not exceed three times net income before unrealized gains and losses on financial instruments, interest, taxes and depreciation, depletion and accretion; (ii) consolidated total debt will not exceed three and one half times consolidated net income before unrealized gains and losses on financial instruments, interest, taxes and depreciation, depletion and accretion; and (iii) consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated unitholders' equity of the Trust, in all cases calculated based on a rolling prior four quarters.

Financing expenses for the year ended December 31, 2008 include interest on bank loans of $29.3 million (2007 – $31.6 million) and convertible debentures of $3.2 million (2007 – $3.6 million). For the year ended December 31, 2008, Bonavista paid cash interest of $32.9 million (2007 – $35.4 million). For the year ending December 31, 2008 our effective interest rate was 3.9% (2007 – 5.3%).

7. 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, 2008 the principal amount outstanding was $6.6 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, 2008 the principal amount outstanding was $38.6 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. 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, 2008:

	Debt Component	Equity Component
(thousands)		
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
Accretion	57	-
Issue expenses related to conversions to trust units	42	-
Amortization of issue expenses	684	-
Conversion to trust units	(5,902)	(121)
Balance, December 31, 2008	**$ 43,711**	**$ 933**

8. Unitholders' equity:

a) Authorized:

Unlimited number of voting trust units.

b) Issued and outstanding:

(i) Trust units:

	Number of Units	Amount
(thousands)		
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
Issued for cash	7,000	214,200
Issued on conversion of convertible debentures	215	5,902
Issued on conversion of exchangeable shares	1,632	5,222
Issued upon exercise of trust unit incentive rights	1,099	19,957
Conversion of restricted trust units	67	-
Issue costs, related to debenture conversions	-	(42)
Issue costs, net of future tax benefit	-	(7,924)
Adjustment to equity component of debenture on conversion	-	121
Unit-based compensation	-	11,768
Balance, December 31, 2008	**95,770**	**$ 1,099,835**

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, 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
Unit-based compensation expense		11,049
Unit-based compensation capitalized		2,037
Exercise of trust unit incentive rights and conversion of restricted trust units		(11,768)
Balance, December 31, 2008	**$**	**10,687**

(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, 2008		**2007**	
	Number	**Amount**	**Number**	**Amount**
(thousands)				
Balance, beginning of year	12,230	$ 74,710	12,297	$ 75,121
Exchanged for trust units	(855)	(5,222)	(67)	(411)
Balance, end of year	**11,375**	**$ 69,488**	**12,230**	**$ 74,710**
Exchange ratio, end of year	1.96225	-	1.72244	-
Trust units issuable on exchange	**22,321**	**$ 69,488**	**21,066**	**$ 74,710**

As a result of minimal conversions of exchangeable shares into trust units over the last few years, Bonavista elected to redeem 10% of its exchangeable shares outstanding on January 16, 2009. This redemption will allow Bonavista to manage the dilution created by the compounding effect of the exchangeable shares, maintain an optimal capital and tax efficient trust structure for the Trust and its unitholders. On January 16, 2009, 1.1 million exchangeable shares were redeemed for 2.3 million trust units.

On July 2, 2013, 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 number of trust unit rights available under both long-term incentive plans shall be limited to 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 two years after each vesting date.

	Number of Trust Unit Incentive Rights	Weighted Average Exercise Price
Balance, December 31, 2006	3,698,475	$ 24.67
Granted	894,900	30.70
Exercised	(682,575)	(11.93)
Expired and forfeited	(184,675)	(27.94)
Reduction in exercise price	-	(3.53)
Balance, December 31, 2007	3,726,125	24.76
Granted	960,840	33.68
Exercised	(1,099,250)	(18.16)
Expired and forfeited	(378,920)	(26.54)
Reduction in exercise price	-	(3.60)
Balance, December 31, 2008	**3,208,795**	**$ 25.88**
Exercisable, December 31, 2008	**688,900**	**$ 22.28**

The following table summarizes trust unit incentive rights outstanding and exercisable under the plan at December 31, 2008:

	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 – 23.00	479,815	1.4	$ 16.07	203,200	$ 15.29
23.01 – 25.50	1,160,700	2.5	24.85	326,725	24.86
25.51 – 35.00	1,568,280	4.5	29.64	158,975	25.93
$ 1.00 – 35.00	3,208,795	3.3	$ 25.88	688,900	$ 22.28

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% (2007 - 3.5%); volatility of 32% (2007 - 31%); a forfeiture rate of 10% (2007 - 10%) and an expected life of 4.5 years. The fair value of the options granted in 2008 average $9.05 (2007 - $8.44) 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 both long-term incentive plans 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, at the discretion of Trust, the holder will receive for each unit award, including distributions made on the trust units from the date of the grant to and including the vesting date, net of statutory withholding tax, either: (i) equivalent trust units; or (ii) the cash equivalent.

The following table summarizes the restricted trust unit's outstanding under the plan at December 31, 2008:

Balance, December 31, 2007	159,739
Granted	78,720
Forfeited	(17,215)
Conversion of restricted trust units	(70,671)
Balance, December 31, 2008	**150,573**

For the year ended December 31, 2008, the Trust expensed $3.7 million (2007 – $2.2 million) 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, 2008	2007
(thousands)		
Trust units	91,703	85,350
Exchangeable shares converted at the exchange ratio	22,487	20,193
Basic equivalent trust units	114,190	105,543
Convertible debentures	1,713	1,891
Trust unit incentive rights	435	641
Restricted trust units	130	-
Diluted equivalent trust units	**116,468**	**108,075**

For the purposes of calculating net income per trust unit on a diluted basis, the net income has been increased by $4.0 million (2007 - $4.4 million) with respect to the accretion, amortization and interest expense on the convertible debentures. For the year ended December 31, 2008 the Trust excluded $874,000 (2007 - $1.7 million) 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 $2,569		(5,994)
Balance, December 31, 2007	**$**	**-**

9. 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, 2008		2007
Expected tax rate		29.8%		32.6%
(thousands)				
Expected tax expense	$	145,436	$	70,955
Effect of change in tax rate		(761)		(10,872)
Distributions to unitholders		(99,142)		(99,673)
SIFT tax, net of tax rate reduction		-		36,444
Other		3,918		2,611
Provision for income taxes (reductions)	**$**	**49,451**	**$**	**(535)**
The provision for income taxes consists of:				
Current	$	-	$	-
Future (reduction)		49,451		(535)
Provision for income taxes (reductions)	**$**	**49,451**	**$**	**(535)**

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

		2008		2007
(thousands)				
Oil and natural gas properties	$	167,146	$	156,540
Facilities		41,214		38,599
Asset retirement obligations		(31,107)		(28,518)
Unrealized financial instruments		22,221		(13,517)
Future income taxes	**$**	**199,474**	**$**	**153,104**

For the years ended December 31, 2008 and 2007 Bonavista paid no tax installments.

10. Financial instruments:

The Trust has exposure to credit, liquidity and market risks from its use of financial instruments. This note provides information about the Trust's exposure to each of these risks, the Trust's objectives, policies and processes for measuring and managing risk. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors has overall responsibility for the establishment and oversight of the Trust's risk management framework. The Board has implemented and monitors compliance with risk management policies. The Trust's risk management policies are established to identify and analyze the risks faced by the Trust, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Trust's activities.

(a) Credit risk:

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations. The Trust is exposed to credit risk with respect to its accounts receivable and commodity price risk contracts. A majority of the Trusts accounts receivable relate to oil and natural gas sales which are exposed to typical industry credit risks. The Trust manages this risk by entering into sales contracts with established creditworthy entities along with reviewing our exposure to these entities on a quarterly basis. The Trust also reduces its credit risk of commodity prices risk contracts by entering into agreements with counterparties that are either i) part of our existing banking syndicate or ii) have an investment grade rating.

Substantially all of the Trust's crude oil and natural gas production is marketed under standard industry terms. Receivables from crude oil and natural gas marketers are normally collected on the 25th day of the month following production. The Trust's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large credit worthy purchasers and to sell through multiple purchasers. The Trust historically has not experienced any collection issues with its crude oil and natural gas marketers. Joint venture receivables are typically collected within three months of the joint venture bill being issued to the partner. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to the expenditure. However, the receivables are from participants in the crude oil and natural gas sector, and collection of the outstanding balances can be impacted by industry factors such as commodity price fluctuations, limited capital availability and unsuccessful drilling programs. The Trust does not typically obtain collateral from crude oil and natural gas marketers or joint venture partners; however the Trust does have the ability in most cases to withhold production from joint venture partners in the event of non-payment.

The carrying amount of accounts receivable represents the maximum credit exposure. As at December 31, 2008 the Trust's receivables consisted of $65.1 million of receivables from crude oil and natural gas marketers which has substantially been collected, $23.8 million from joint venture partners of which $6.3 million has been subsequently collected, and $17.2 million of Crown deposits and prepaid expenses. As at December 31, 2008 the Trust has $9.8 million in accounts receivable that is considered to be past due. Although these amounts have been outstanding for greater than 90 days, they are still deemed to be collectible. The Trust does not have an allowance for doubtful accounts as at December 31, 2008 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the period ended December 31, 2008.

(b) Liquidity risk:

Liquidity risk is the risk that the Trust will encounter difficulty in meeting obligations associated with the financial liabilities. The Trust's financial liabilities consist of accounts payable and accrued liabilities, financial instruments, bank debt and convertible debentures. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities, capital expenditures, and distributions payable. The Trust processes invoices within a normal payment period. Accounts payable and financial instruments have contractual maturities of less than one year. The Trust maintains a three year revolving credit facility, as outlined in note 6, which may, at the request of the Trust with the consent of the lenders, be extended on an annual basis. The Trust also has two series of convertible debentures outstanding. The 7.5% debentures have a conversion price of $23.00 per trust unit, maturing on June 30, 2009 and the 6.75% debentures have a conversion price of $29.00 per trust unit, maturing on June 30, 2010. The Trust may elect to satisfy the principal obligation of these debentures by issuing trust units to the holders of the debentures. The Trust also maintains and monitors a certain level of cash flow which is used to partially finance all operating, investing and capital expenditures.

(c) Market risk:

Market risk is the risk that changes in market conditions, such as commodity prices, interest rates, and foreign exchange rates, will affect the Trust's net income or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing the Trust's returns.

The Trust utilizes both financial instruments and physical delivery sales contracts to manage market risks. All such transactions are conducted in accordance with the Trust's risk management policy that has been approved by the Board of Directors.

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for crude oil and natural gas are impacted not only by global economic events that dictate the levels of supply and demand but also by the relationship between the Canadian and United States dollar. The Trust has attempted to mitigate a portion of the commodity price risk through the use of various financial instruments and physical delivery sales contracts. The Trust's policy is to enter into commodity price contracts when considered appropriate to a maximum of 60% of net after royalty, forecasted production volumes.

i) Financial instruments:

As at December 31, 2008, the Trust has hedged by way of costless collars to sell natural gas and crude oil as follows:

Volume	**Average Price**			**Term**
10,000 gjs/d	CDN$ 9.25	-	CDN$ 13.50 – AECO	January 1, 2009 – March 31, 2009
10,000 gjs/d	CDN$ 7.50	-	CDN$ 9.50 – AECO	April 1, 2009 – October 31, 2009
5,000 mmbtu/d	US$ 6.81	-	US$ 7.91 – AECO	January 1, 2009 – March 31, 2009
1,000 bbls/d	CDN$ 70.00	-	CDN$ 78.00 – Bow River	January 1, 2009 – December 31, 2009
3,000 bbls/d	CDN$ 81.67	-	CDN$ 121.33 – WTI	January 1, 2009 – December 31, 2009
2,000 bbls/d	US$ 65.00	-	US$ 80.50 – WTI	January 1, 2009 – March 31, 2009
1,000 bbls/d	US$ 85.00	-	US$ 105.60 – WTI	January 1, 2009 – December 31, 2009
2,000 bbls/d	CDN$ 105.00	-	CDN$ 169.00 – WTI	April 1, 2009 – December 31, 2009

Financial instruments are recorded on the consolidated balance sheet at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the consolidated statements of operations, comprehensive income and accumulated earnings. As at December 31, 2008 the fair market value recorded on the consolidated balance sheet for these financial instruments was an asset of $76.2 million, compared to a liability of $45.1 million in 2007. These financial instruments had the following gains and losses reflected in the consolidated statements of operations, comprehensive income and accumulated earnings:

	Years ended December 31, 2008	**2007**
Realized gains (losses) on financial instruments	$ (80,806)	$ (665)
Unrealized gains (losses) on financial instruments	121,261	(45,058)
	$ 40,455	$ (45,723)

Bonavista mitigates its risk associated with fluctuations in commodity prices by utilizing financial instruments. A $0.10 increase or a $0.10 decrease to the price per thousand cubic feet of natural gas – AECO would have an impact of approximately $5.2 million and $5.4 million respectively, on net income for those financial instruments that were in place as at December 31, 2008. A $1.00 increase or a $1.00 decrease to the price per barrel of oil – WTI would have an impact of approximately of $5.1 million and $2.6 million respectively, on net income for those financial instruments that were in place as at December 31, 2008.

ii) Physical purchase contracts:

As at December 31, 2008, the Trust has entered into direct sale costless collars to sell natural gas as follows:

Volume	**Average Price (CDN$ - AECO)**	**Term**
40,000 gjs/d	$ 8.16 - $ 10.69	January 1, 2009 – March 31, 2009
10,000 gjs/d	$ 8.00 - $ 10.84	April 1, 2009 – October 31, 2009

Physical purchase contracts are being accounted for as they are settled.

iii) Foreign currency exchange rate risk:

Foreign currency exchange rate risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in foreign exchange rates. The Trust sells crude oil and natural gas that is denominated in both US and Canadian dollars. Canadian commodity prices are influenced by fluctuations in the Canadian to U.S. dollar exchange rate. The Trust had no forward exchange rate contracts in place as at or during the period ended December 31, 2008.

iv) Interest rate risk:

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. The Trust is exposed to interest rate fluctuations on its bank debt which bears a floating rate of interest. If the interest rates applicable to Bonavista's bank debt were to change by 100 basis points and assuming that the changes in bank debt are consistent with what actually occurred in the period, we would estimate that net income for the year ended December 31, 2008 would have a $5.0 million (2007 - $4.6 million) impact. The sensitivity impact is higher for the year ended in 2008 because of higher weighted average bank debt compared to the year ended December 31, 2007, notwithstanding that the weighted average interest rate is lower in 2008 compared to the same period in 2007. The Trust had no interest rate swap or financial contracts in place as at or during the period ended December 31, 2008.

Fair value of financial instruments

The Trust's financial instruments as at December 31, 2008 and December 31, 2007 include accounts receivable, derivative contracts, accounts payable, distributions payable and accrued liabilities, convertible debentures and bank debt. The fair value of accounts receivable, accounts payable, distributions payable and accrued liabilities approximate their carrying amounts due to their short-terms to maturity.

The fair value of financial instruments is determined by the financial intermediary to extinguish all rights or obligations of the financial instruments. As at December 31, 2008, the fair market value of these financial instruments was a gain of approximately $76.2 million. For the similar period in 2007, the fair market value of these financial instruments was a deficiency of $45.1 million.

Fair market value of the convertible debentures as at December 31, 2008 is $44.4 million (2007 - $52.5 million), as determined by its most recent closing trading price.

Bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

11. Capital management:

The Trust's objective when managing capital is to maintain a flexible capital structure which allows it to execute its growth strategy through strategic acquisitions and expenditures on exploration and development activities while maintaining a strong financial position that provides our unitholders with stable distributions and rates of return.

The Trust considers its capital structure to include working capital (excluding unrealized gains and losses on financial instruments), convertible debentures, bank debt, and unitholders' equity. The Trust monitors capital based on the ratio of net debt to annualized funds from operations. The ratio represents the time period it would take to pay off the debt if no further capital expenditures were incurred and if funds from operations remained constant. This ratio is calculated as net debt, defined as outstanding bank debt plus or minus net working capital, divided by funds from operations for the most recent calendar quarter, annualized (multiplied by four). The Trust's strategy is to maintain a ratio of no more than 2.0 to 1. This strategy is more restrictive than the existing financial covenants on the Trust's credit facility. This ratio may increase at certain times as a result of acquisitions or low commodity prices. As at December 31, 2008, the Trust's ratio of net debt to annualized funds from operations was 1.2 to 1 (2007 –1.4 to 1), which is within the acceptable range established by the Trust.

In order to facilitate the management of this ratio, the Trust prepares annual funds from operations and capital expenditure budgets, which are updated as necessary, and are reviewed and periodically approved by the Trust's Board of Directors. The Trust manages its capital structure and makes adjustments by continually monitoring its business conditions, including; the current economic conditions; the risk characteristics of the Trust's crude oil and natural gas assets; the depth of its investment opportunities; current and forecasted net debt levels; current and forecasted commodity prices; and other factors that influence commodity prices and funds from operations, such as quality and basis differential, royalties, operating costs and transportation costs.

In order to maintain or adjust the capital structure, the Trust will consider; its forecasted ratio of net debt to forecasted funds from operations while attempting to finance an acceptable capital expenditure program including acquisition opportunities; the current level of bank credit available from the Trust's lenders; the level of bank credit that may be attainable from its lenders as a result of crude oil and natural gas reserves; the availability of other sources of debt with different characteristics than the existing bank debt; the sale of assets; limiting the size of the capital expenditure program; issuance of new equity if available on favourable terms; and its level of distributions payable to its unitholders. The Trust's unitholder's capital is not subject to external restrictions, however the Trust's credit facility does contain financial covenants that are outlined in note 6 of the consolidated financial statements.

There has been no change in the Trust's approach to capital management during the period ended December 31, 2008.

12. Commitments:

The following is a summary of the Trust’s commitments as at December 31, 2008:

	Payments Due by Period					
	Total	**2009**	**2010**	**2011**	**2012**	**2013 and thereafter**
(thousands)						
Transportation expenses	$ 32,987	$ 11,160	$ 5,653	$ 4,054	$ 3,159	$ 8,961
Office premises	3,235	1,527	1,412	296	-	-
Total commitments	**$ 36,222**	**$ 12,687**	**$ 7,065**	**$ 4,350**	**$ 3,159**	**$ 8,961**

CORPORATE INFORMATION

DIRECTORS

Keith A. MacPhail,
Chairman and CEO
Ian S. Brown,
Independent Businessman
Michael M. Kanovsky,
Sky Energy Corporation
Harry L. Knutson,
Nova Bancorp Inc.
Margaret A. McKenzie,
Range Royalty Management Ltd.
Ronald J. Poelzer,
Executive Vice President and Vice Chairman
Christopher P. Slubicki,
Independent Businessman
Walter C. Yeates,
Independent Businessman

OFFICERS

Keith A. MacPhail,
Chairman and CEO
Jason E. Skehar,
President and COO
Ronald J. Poelzer,
Executive Vice President and Vice Chairman
Glenn A. Hamilton,
Senior Vice President and CFO
Thomas J. Mullane,
Senior Vice President, Engineering
Johannes H. Thiessen,
Senior Vice President, Exploration
Orest G. Humeniuk,
Vice President, Land
Dean M. Kobelka,
Vice President, Finance
Lynda J. Robinson,
Vice President, Human Resources and Administration
Hank R. Spence,
Vice President, Operations
Grant A. Zawalsky,
Corporate Secretary

AUDITORS

KPMG LLP
Chartered Accountants
Calgary, Alberta

BANKERS

Canadian Imperial Bank of Commerce
Bank of Montreal
Royal Bank of Canada
The Bank of Nova Scotia
The Toronto-Dominion Bank
Alberta Treasury Branches
National Bank of Canada
Union Bank of California, N.A. (Canada Branch)
Fortis Capital (Canada)
HSBC Bank Canada
Société Générale (Canada Branch)
Sumitomo Mitsui Banking Corporation of Canada
Calgary, Alberta

ENGINEERING CONSULTANTS

GLJ Petroleum Consultants Ltd.
Ryder Scott Company Canada
Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Valiant Trust Company
Calgary, Alberta

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading Symbol "BNP.UN", "BNP.DB" and "BNP.DB.A"

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BONAVISTA ENERGY TRUST