

Press Release July 29, 2010

Calgary - Bonavista Energy Trust is pleased to report to unitholders its interim consolidated financial and operating results for the three and six months ended June 30, 2010.

Highlights

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Financial				
(\$ thousands, except per unit)				
Production revenues	227,732	166,430	481,364	345,576
Funds from operations ⁽¹⁾	130,068	101,655	276,167	207,340
Per unit ⁽¹⁾⁽²⁾	0.85	0.85	1.84	1.74
Distributions declared	63,860	47,430	123,950	102,504
Per unit	0.48	0.48	0.96	1.04
Percentage of funds from operations ⁽¹⁾	49%	47%	45%	49%
Net income	45,449	661	125,183	33,620
Per unit ⁽²⁾	0.30	0.01	0.83	0.28
Adjusted net income ⁽³⁾	43,464	35,227	105,677	80,688
Per unit ⁽²⁾	0.28	0.29	0.70	0.68
Total assets			3,354,705	2,496,168
Long-term debt, net of working capital ⁽⁴⁾			987,288	668,637
Long-term debt, net of adjusted working capital ⁽³⁾⁽⁴⁾			999,870	680,848
Unitholders' equity			1,913,272	1,351,059
Capital expenditures:				
Exploration and development	68,557	41,350	170,430	98,498
Acquisitions, net	248,360	128	245,147	22,225
Weighted average outstanding equivalent trust units: (thousands) ⁽²⁾				
Basic	153,632	119,726	150,148	119,238
Diluted	155,952	121,851	152,488	121,174
Operating				
(boe conversion – 6:1 basis)				
Production:				
Natural gas (mmcf/day)	238	176	232	174
Oil and liquids (bbls/day)	26,187	22,378	25,704	22,567
Total oil equivalent (boe/day)	65,885	51,768	64,318	51,559
Product prices: ⁽⁵⁾				
Natural gas (\$/mcf)	4.47	4.19	4.95	5.26
Oil and liquids (\$/bbl)	57.06	58.61	60.05	54.97
Operating expenses (\$/boe)	7.94	10.25	8.31	10.37
General and administrative expenses (\$/boe)	0.88	0.89	0.88	0.86
Cash costs (\$/boe) ⁽⁶⁾	9.67	11.68	10.04	11.90
Operating netback (\$/boe) ⁽⁷⁾	23.43	23.01	25.45	23.75

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) Amounts have been adjusted to exclude unrealized gains and losses on financial instrument contracts, their related tax impact and associated assets or liabilities.
- (4) Amounts exclude convertible debentures.
- (5) Product prices include realized gains and losses on financial instrument contracts.
- (6) Cash costs equal the total of operating, general and administrative, and financing expenses.
- (7) Operating netback equals production revenues including realized gains and losses on financial instrument contracts, less royalties, transportation and operating expenses, calculated on a boe basis.

Trust Unit Trading Statistics	Three months ended			
	June 30, 2010	March 31, 2010	December 31, 2009	September 30, 2009
(\$ per unit, except volume)				
High	25.60	25.70	24.00	21.89
Low	22.03	22.40	19.86	16.64
Close	22.81	23.35	22.30	20.42
Average Daily Volume - Units	423,688	341,312	314,701	566,846

MESSAGE TO UNITHOLDERS

Bonavista Energy Trust (“Bonavista” or the “Trust”) is pleased to report to unitholders (the “Unitholders”) its consolidated financial and operating results for the three and six months ended June 30, 2010. Bonavista has continued its pattern of generating profitable results since commencing operations as an energy trust in July 2003. Despite continued volatility in both commodity and capital markets during the first half of 2010, we remained focused on the consistent execution of Bonavista’s proven business strategies which has resulted in excellent operational and financial results.

Given the four year transition period for income trusts is nearly complete, we anticipate the conversion to a dividend paying corporation at the end of 2010 and the subsequent pursuit of a hybrid business model that is designed to provide our investors a combination of growth and income. We will provide more detailed guidance including targeted growth rates and payout ratios closer to year end. In the interim, we continue to introduce incremental operational and capital efficiencies into our business through cost discipline and the application of new technologies to both heritage assets and recently acquired properties. Over the past few years, we have strategically assembled a robust inventory of growth opportunities that will complement this hybrid business model for many years to come.

The first half of 2010 was characterized by an active and successful exploration and development drilling program coupled with a successful acquisition program which has led to significant increases in production and reserves at attractive reinvestment efficiencies. With these successful results, Bonavista has approved a modest increase to its 2010 capital program to between \$600 and \$630 million. This is comprised of \$280 million in acquisition funding, with the remaining \$320 to \$350 million allocated to expanding our exploration and development program, drilling between 140 and 150 wells. As a result, Bonavista is increasing its 2010 production guidance by approximately 2,000 boe per day and now expects production to average between 66,500 and 67,500 boe per day.

In the second quarter of 2010, Bonavista closed its previously announced acquisition of certain long-life, liquid rich, natural gas weighted assets (the “Acquired Properties”) creating a new core area in west central Alberta. This acquisition closed on May 31, 2010 for a cash purchase price of \$230.4 million and was partially funded by our \$177.0 million equity financing completed on April 15, 2010. The acquisition is consistent with Bonavista’s strategy of acquiring high quality, long reserve life assets with significant low risk development potential. The Acquired Properties provide a stable foundation of production and infrastructure, complementing our deep basin land position in west central Alberta. In addition, the Acquired Properties offer an opportunity for Bonavista to expand our application of leading technologies to access large, underdeveloped reservoirs, much like we have done over the past year in our Western Core Region. Bonavista anticipates drilling approximately six wells on the Acquired Properties in 2010, spending approximately \$15 million building our inventory of opportunities for future development.

Other accomplishments for Bonavista in the second quarter of 2010 include:

- Increased production volumes to a record level of 65,885 boe per day. This represents a 27% increase over the 51,768 boe per day of production in the second quarter of 2009. Production additions resulting from our exploration and development program over the first half of 2010 have exceeded our expectations, reinforcing our confidence in the quality of our abundant drilling inventory as we move beyond 2010;
- Executed an effective capital program during the quarter investing \$68.6 million in exploration and development activities drilling 24 wells with an overall 96% success rate. Drilled 21 successful horizontal wells which include unconventional resource development in the Glauconite, Cardium, Notikewin and Elkton horizons. The key highlights of our horizontal drilling program are as follows:
 - a) Drilled 10 horizontal wells on the highly prospective Hoadley Glauconite trend in our Western Core Region. Bonavista has now drilled 45 horizontal Glauconite wells on the Hoadley trend and with four wells awaiting completion and tie-in, the 41 wells currently on production have delivered average initial production rates of 460 boe per day per well which equates to approximately 20,000 boe per day in their first month of production. The production profile of the producing wells to date continues to meet or exceed our expectations. Additionally, average well costs have significantly improved from \$3.5 million per well initially to \$2.5 million per well currently as a result of improved drilling efficiencies and the application of a more scalable development program. Our remaining inventory of 250 horizontal drilling prospects on the Hoadley Glauconite trend will result in an attractive

multi-year development program with on-stream capital efficiencies of approximately \$6,000 per boe per day. Bonavista believes that our Glauconite horizontal development program continues to compete with the top tier liquids rich natural gas resource developments in North America. Single well economics are exceptionally attractive and provide abundant capital spending flexibility with half-cycle breakeven economics at less than \$2.00 per mcf.

- b) Drilled four horizontal wells on the emerging unconventional Cardium light oil play in our Western Core Region. With 15 horizontal Cardium wells drilled to date, we have recently experienced a pattern of consistent results building our confidence in the repeatability and the profitability of this resource play. Initial production rates from our more recent wells have averaged approximately 150 boe per day generating an attractive return on investment at current pricing. In 2010, we will drill 15 to 20 Cardium horizontal wells with the intent of quantifying our development opportunities in the months to come.
- Participated at Crown land sales purchasing approximately 25,000 net acres of undeveloped land, enhancing our ability to sustainably generate profitable drilling opportunities for many years. In the first half of 2010, we have acquired approximately 76,000 acres of undeveloped acreage at Crown land sales which is a record achievement for Bonavista.
- Managed our exposure to commodity price volatility by adding positions to our hedge portfolio. This has resulted in the protection of approximately 32% of our forecasted natural gas production (net of royalties) at an average floor price of \$5.24 per mcf and 44% of our forecasted oil and liquids production (net of royalties) at an average floor price of \$68.56 per bbl for 2010;
- Achieved significant improvements in our cost structure with operating costs on a per boe basis decreasing 23% for the three months ended June 30, 2010 to \$7.94 per boe from \$10.25 per boe in the comparable period of 2009. These improvements stem from continued cost discipline in all operating areas coupled with development drilling in areas where we own and operate infrastructure with ample processing capacity and attractive processing costs;
- Generated funds from operations of \$130.1 million (\$0.85 per unit) for the three months ended June 30, 2010. Bonavista distributed 49% of these funds for the three months ended June 30, 2010 to Unitholders with the remaining funds reinvested in the business to continue growing our production base;
- Continued to record attractive levels of profitability in the second quarter of 2010 with a return on equity of 10% and an adjusted net income to funds from operations ratio of 33%. The above ratios reflect net income adjusted to negate the after tax impact of the unrealized gains and losses on financial instrument contracts; and
- Since inception as a Trust, Bonavista has delivered cumulative distributions of \$1.9 billion or \$22.23 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.

Strengths of Bonavista Energy Trust

Upon restructuring from an exploration and production corporation into an energy trust in July 2003, Bonavista employed the same strategy that resulted in our tremendous success between 1997 and 2003. We have maintained a high level of investment activity on our asset base, increasing current production by approximately 86% since 2003. This activity stems from the operational and technical focus of our people, their attention to detail, and their entrepreneurial approach to generating economic prospects on our asset base within the Western Canadian Sedimentary Basin. Our experienced technical teams have a solid understanding of our assets and they continue to exercise the discipline and commitment required to deliver long-term profitable results to our Unitholders. We actively participate in undeveloped land acquisitions through Crown land sales, property purchases and farm-in opportunities, which have all enhanced the quality and quantity of our extensive low-risk drilling inventory. These activities have led to low cost reserve additions, lengthening of our reserve life index, a significant increase in our drilling inventory and a growing production base. Our production base is weighted 62% in favour of natural gas and is geographically focused within select, multi-zone regions primarily in Alberta and British Columbia. The low cost structure of our asset base maintains attractive operating netbacks in most operating environments. In addition, our asset base is predominantly operated by Bonavista, providing control over the pace of operations and ensuring that operating and capital cost efficiencies are consistently optimized.

Our team brings a successful track record of executing low to medium risk development programs, including both asset and corporate acquisitions, along with a solid track record of sound financial management. Our Board of Directors and management team possess extensive experience in the oil and natural gas business. They have successfully guided our organization through many different economic cycles utilizing a proven strategy consisting of disciplined cost controls and prudent financial management. Directors, management and employees also own approximately 15% of the Trust after giving effect to the recent financing, resulting in the 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, 2009. The following MD&A of the financial condition and results of operations was prepared at, and is dated July 29, 2010. Our audited consolidated financial statements, Annual Report, and other disclosure documents for 2009 are available 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) prospects and inventory; (iv) anticipated production rates; (v) expected royalty rate; (vi) anticipated operating and service costs; (vii) our financial strength; (viii) incremental development opportunities; (ix) expected conversion to a corporation; the timing thereof and our business model; (x) anticipated natural gas supply and demand; (xi) improved natural gas pricing; (xii) reserve life index; (xiii) anticipated operating costs; (xiv) utilization of technology; and (xv) rate of return, 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 and losses on financial instrument contracts, 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 exploration and development program for the first six months of 2010 led to the drilling of 61 wells within our core regions with a success rate of 98%. This program resulted in 34 natural gas wells and 26 oil wells. Profitability continues to guide our exploration and development program which remains flexible to changes in commodity price, development risk and deliverability upside. Once again, our operations in the second quarter have resulted in superior capital efficiencies driven off of strong production performance, healthy reserve additions and a disciplined approach to spending with every well drilled. These activities, along with a significant acquisition completed in the second quarter of 2010, continue to enhance the predictability in our overall production base in addition to lengthening our reserve life index ("RLI") to approximately 11.7 years.

Production - For the second quarter of 2010, production increased 27% to reach a record level of 65,885 boe per day when compared to 51,768 boe per day for the same period a year ago. Natural gas production increased 35% to 238 mmcf per day in the second quarter of 2010 from 176 mmcf per day for the same period a year ago, while total oil and liquids production increased 17% to 26,187 bbls per day in the second quarter of 2010 from 22,378 bbls per day for the same period in 2009. For the six months ended June 30, 2010, production increased 25% to 64,318 boe per day when compared to 51,559 boe per day for the same period a year ago. Natural gas production increased 33% to 232 mmcf per day in the first six months of 2010 from 174 mmcf per day for the same period a year ago, while total oil and liquids production increased 14% to 25,704 bbls per day in the first six months of 2010 from 22,567 bbls per day for the same period in 2009.

The following table highlights Bonavista's production by product for the three and six months ended June 30:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Natural gas (mmcf/day)	238	176	232	174
Oil and liquids (bbls/day):				
Light and medium oil	21,047	16,531	20,766	16,874
Heavy oil	5,140	5,847	4,938	5,693
Total oil and liquids (bbls/day)	26,187	22,378	25,704	22,567
Total oil equivalent (boe/day)	65,885	51,768	64,318	51,559

Our current production is approximately 68,500 boe per day, consisting of 62% natural gas, 31% light and medium oil and 7% heavy oil.

Production revenues - Production revenues for the second quarter of 2010 increased 37% to \$227.7 million when compared to \$166.4 million for the same period a year ago, due mainly to increased production volumes. For the three months ended June 30, 2010, natural gas prices increased 7% to \$4.47 per mcf, when compared to \$4.19 per mcf realized in the same period in 2009. The average oil and liquids price decreased 3% to \$57.06 per bbl for the three months ended June 30, 2010 from \$58.61 per bbl for the same period in 2009. For the six months ended June 30, 2010, production revenues increased 39% to \$481.4 million when compared to \$345.6 million for the same period a year ago, largely due to increased production volumes. In the first half of 2010, natural gas prices decreased 6% to \$4.95 per mcf, when compared to \$5.26 per mcf realized in the same period in 2009. The average oil and liquids price increased 9% to \$60.05 per bbl for the six months ended June 30, 2010 from \$54.97 per bbl for the same period in 2009.

The following table highlights Bonavista's realized commodity pricing for the three and six months ended June 30:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Natural gas (\$/mcf):				
Production revenues	\$ 4.25	\$ 3.82	\$ 4.83	\$ 4.92
Realized gain on financial instrument contracts	0.22	0.37	0.12	0.34
	4.47	4.19	4.95	5.26
Light and medium oil (\$/bbl):				
Production revenues	56.93	50.35	59.59	46.83
Realized gain on financial instrument contracts	0.11	8.88	0.11	9.96
	57.04	59.23	59.70	56.79
Heavy oil (\$/bbl):				
Production revenues	57.08	55.23	61.47	46.34
Realized gain on financial instrument contracts	0.03	1.60	0.07	3.22
	57.11	56.83	61.54	49.56
Total (\$/boe):				
Production revenues	37.98	35.33	41.35	37.03
Realized gain on financial instrument contracts	0.84	4.29	0.47	4.77
	\$ 38.82	\$ 39.62	\$ 41.82	\$ 41.80

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 using costless collars limits Bonavista's exposure to downturns in commodity prices, while allowing for participation in commodity price increases.

For the second quarter of 2010, our risk management program on financial instrument contracts resulted in a net gain of \$7.4 million, consisting of a realized gain of \$5.1 million and an unrealized gain of \$2.3 million. The realized gain of \$5.1 million consisted of a \$4.9 million gain on natural gas commodity derivative contracts and a \$215,000 gain on crude oil commodity derivative contracts. For the same period in 2009, our risk management program on financial instruments resulted in a net loss of \$27.8 million, consisting of a realized gain of \$20.2 million and an unrealized loss of \$48.0 million. The realized gain of \$20.2 million consisted of a \$6.0 million gain on natural gas commodity derivative contracts and a \$14.2 million gain on crude oil commodity derivative contracts.

For the six months ended June 30, 2010, our risk management program on financial instrument contracts resulted in a net gain of \$32.4 million, consisting of a realized gain of \$5.5 million and an unrealized gain of \$26.9 million. The realized gain of \$5.5 million consisted of a \$5.0 million gain on natural gas commodity derivative contracts and a \$488,000 gain on crude oil commodity derivative contracts. For the same period in 2009, our risk management program on financial instrument contracts resulted in a net loss of \$20.8 million, consisting of a realized gain of \$44.5 million and an unrealized loss of \$65.3 million. The realized gain of \$44.5 million consisted of a \$10.8 million gain on natural gas commodity derivative contracts and a \$33.7 million gain on crude oil commodity derivative contracts.

Royalties - For the three months ended June 30, 2010, royalties increased by 67% to \$35.1 million from \$21.0 million for the same period a year ago, largely attributed to a significant increase in production volumes. In addition, royalties as a percentage of revenues (including realized gains and losses on financial instrument contracts) for the second quarter of 2010 increased to 15.1% compared to 11.2% in 2009. The increase in royalty rates is due largely from the impact of lower realized gains on financial instrument contracts, a 13% increase in oil and liquids pricing and a higher percentage of natural gas liquids production volumes that attract higher royalty rates. For the six months ended June 30, 2010, royalties increased by 40% to \$75.3 million from \$53.9 million for the same period a year ago, for similar reasons as stated above. In addition, royalties as a percentage of revenues (including realized gains and losses on financial instrument contracts) for the first six months of 2010 increased to 15.5% compared to 13.8% in 2009. The increase in royalty rates is again largely due to similar reasons as discussed above.

The following table highlights Bonavista's royalties by product for the three and six months ended June 30:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Natural gas (\$/mcf):				
Royalties	0.40	0.45	0.50	0.78
% of revenues ⁽¹⁾	9.0%	10.8%	10.0%	14.9%
Light and medium oil (\$/bbl):				
Royalties	11.17	6.52	11.80	7.40
% of revenues ⁽¹⁾	19.6%	11.0%	19.8%	13.0%
Heavy oil (\$/bbl):				
Royalties	10.73	7.27	11.37	6.42
% of revenues ⁽¹⁾	18.8%	12.8%	18.5%	13.0%

⁽¹⁾ % of revenues include realized gains and losses on financial instrument contracts

On January 1, 2009 the Alberta Government's New Royalty Framework ("NRF") took effect. Subsequent to this legislation the Government of Alberta has introduced a number of programs to stimulate new and continued economic activity in Alberta. The Transitional Royalty Plan ("TRP"), which expires December 31, 2013, offers reduced royalty rates for new wells drilled that meet certain depth requirements. In addition to the TRP, a second royalty incentive program was announced by the Government of Alberta. The Three Point Incentive Plan includes a drilling royalty credit for new conventional oil and natural gas wells and a new royalty incentive program, this program is set to expire on March 31, 2011 and will add approximately \$26.0 million in royalty and drilling credits for 2010.

On March 11, 2010 the Alberta Competitiveness Review board made a number of recommendations for further improvements to Alberta's current royalty structure. These recommendations become effective on a permanent basis for the January 2011 production month and are outlined as follows:

- The current incentive program rate of 5% on new natural gas and conventional oil wells will become a permanent feature of the royalty system, with the current time and volume limits;
- The maximum royalty rate for conventional oil will be reduced at higher price levels from 50% to 40% to provide better risk-reward balance to investors;
- Recognizing the fundamental changes to the North American supply/demand balance and increased competition from other jurisdictions, the maximum royalty rate for conventional and unconventional natural gas will be reduced at higher price levels from 50% to 36%; and
- The NRF legislated in November 2008 will continue until its original announced expiration on December 31, 2013. Effective January 1, 2011, no new wells will be allowed to select the transitional royalty rates. Wells that have already selected the transitional royalty rates will have the option to stay with those rates or switch to the new rates effective January 1, 2011.

On May 27, 2010 the Government of Alberta revealed its proposed changes to the base royalty curves for both conventional oil and natural gas, which are to take effect on January 1, 2011. The Government also unveiled further initiatives, as a result of the competitiveness review, intended to energize investment and encourage development of Alberta's unconventional and deep resource pools. The most significant of these initiatives are modifications to the natural gas deep drilling program and the implementation of the emerging resources and technologies initiative. The change in the qualifying depth of the deep drilling program from 2,500 to 2,000 meters true vertical depth has increased the number of horizontal wells applicable for this credit by approximately 100 wells in our Hoadley Glauconite development program. This depth change will result in a significant royalty credit of approximately \$1.0 million per Glauconite horizontal well.

Operating expenses - Operating expenses for the three months ended June 30, 2010 remained relatively unchanged at \$47.6 million compared to \$48.3 million for the same period a year ago. For the three months ended June 30, 2010 operating costs on a per boe basis decreased 23% to \$7.94 per boe compared to \$10.25 per boe in the comparable period of 2009. This significant decrease on a per boe basis is attributed to efficiency gains derived from production additions through our recent drilling and acquisition activities along with our ongoing operating cost reduction initiatives. Operating expenses for the first half of 2010 remained unchanged at \$96.7 million compared to \$96.7 million for the same period a year ago. For the six months ended June 30, 2010 operating costs on a per boe basis decreased 20% to \$8.31 per boe, from \$10.37 per boe in the comparable period of 2009 for similar reasons as stated above. Bonavista anticipates that operating costs on a per boe basis will decrease in 2010 to approximately \$8.00 to \$8.50 per boe as compared to the average \$9.80 per boe in 2009.

The following table highlights Bonavista's operating expenses by product for the three and six months ended June 30:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Natural gas (\$/mcf)	\$ 1.10	\$ 1.48	\$ 1.17	\$ 1.52
Light and medium oil (\$/bbl)	8.92	10.87	9.28	10.93
Heavy oil (\$/bbl)	14.35	15.47	14.43	15.20
Total (\$/boe)	\$ 7.94	\$ 10.25	\$ 8.31	\$ 10.37

Transportation expenses - For the three months ended June 30, 2010, transportation expenses increased 7% to \$9.7 million (\$1.61 per boe) compared to \$9.0 million (\$1.91 per boe) for the same period in 2009. For the six months ended June 30, 2010, transportation expenses increased 4% to \$18.5 million (\$1.58 per boe) compared to \$17.8 million (\$1.90 per boe) for the same period in 2009. Per unit transportation costs have decreased 17% over this period as a result of our significant increase in production volumes in areas with lower associated transportation costs.

The following table highlights Bonavista's transportation expenses by product for the three and six months ended June 30:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Natural gas (\$/mcf)	\$ 0.30	\$ 0.34	\$ 0.30	\$ 0.35
Light and medium oil (\$/bbl)	0.84	0.93	0.83	0.91
Heavy oil (\$/bbl)	3.19	4.05	3.27	3.93
Total (\$/boe)	\$ 1.61	\$ 1.91	\$ 1.58	\$ 1.90

General and administrative expenses - General and administrative expenses, after overhead recoveries, increased 25% to \$5.3 million for the three months ended June 30, 2010 from \$4.2 million in the same period in 2009 and increased 27% to \$10.2 million for the six months ended June 30, 2010 from \$8.0 million in the same period in 2009. These increases are largely due to higher costs of personnel required to manage our growing operations. On a per boe basis, general and administrative expenses remained relatively unchanged for the three months ended June 30, 2010 at \$0.88 per boe from \$0.89 per boe in the same period in 2009 and increased 2% to \$0.88 per boe for the six months ended June 30, 2010 from \$0.86 per boe in the same period in 2009. Our current level of general and administrative expenses still remains among the lowest in our sector on a per boe basis.

In connection with its Trust Unit Incentive Rights and Restricted Trust Unit Plans, Bonavista recorded a unit-based compensation charge of \$2.7 million and \$5.5 million for the three and six months ended June 30, 2010 respectively, compared to \$2.8 million and \$5.6 million for the same periods in 2009.

Financing expenses - Financing expenses, which include interest expense on long-term debt and convertible debentures, increased 103% to \$5.2 million for the three months ended June 30, 2010, from \$2.5 million for the same period in 2009 and on a per boe basis, increased 59% to \$0.86 per boe for the three months ended June 30, 2010 from \$0.54 per boe for the same period in 2009. For the six months ended June 30, 2010, financing expenses increased 59% to \$9.9 million from \$6.3 million for the same period in 2009 and on a per boe basis, increased 27% to \$0.85 per boe for the first half of 2010 from \$0.67 per boe for the same period in 2009. The increase in financing expenses for the three months ended June 30, 2010 compared to the same period in 2009 is largely the result of an increase in our bank loan facilities used to finance, in part, two significant acquisitions that we closed on August 20, 2009 and May 31, 2010. During the second quarter of 2010, Bonavista paid cash interest of \$5.8 million compared to \$3.3 million for the same period in 2009. For the six months ended June 30, 2010, Bonavista paid cash interest of \$9.8 million compared to \$6.8 million for the same period in 2009. Bonavista's effective interest rate as at June 30, 2010 was approximately 2.4% (2009 – 1.0%).

Depreciation, depletion and accretion expenses - Depreciation, depletion and accretion expenses increased 33% to \$89.0 million for the three months ended June 30, 2010 from \$66.7 million for the same period of 2009. For the six months ended June 30, 2010, depreciation, depletion and accretion expenses increased 30% to \$171.4 million from \$132.3 million for the same period of 2009. This increase is due to higher costs of finding, developing and acquiring reserves and a larger production base in 2010. For the three months ended June 30, 2010, the average cost increased to \$14.85 per boe from \$14.17 per boe for the same period in 2009 and for the six months ended June 30, 2010, the average cost increased to \$14.72 per boe from \$14.18 per boe for the same period a year ago.

Income taxes - For the three months ended June 30, 2010, the income tax recovery was \$5.0 million compared to an income tax recovery of \$16.5 million for the same period in 2009. For the six months ended June 30, 2010, the provision for income taxes was \$2.9 million compared to an income tax recovery of \$29.4 million for the same period in 2009. The provision for the six months ended June 30, 2010 is mainly attributable to the unrealized gain on financial instrument contracts. Bonavista made no cash payments on tax installments for the three and six months ended June 30, 2010, or for the comparative periods in 2009.

Funds from operations, net income and comprehensive income - For the three months ended June 30, 2010, Bonavista experienced a 28% increase in funds from operations to \$130.1 million (\$0.85 per unit, basic) from \$101.7 million (\$0.85 per unit, basic) for the same period in 2009. For the six months ended June 30, 2010, Bonavista experienced a 33% increase in funds from operations to \$276.2 million (\$1.84 per unit, basic) from \$207.3 million (\$1.74 per unit, basic) for the same period in 2009. Funds from operations increased for the three months ended June 30, 2010 due to increased production volumes and to a less extent slightly higher natural gas prices. Net income and comprehensive income for the three months ended June 30, 2010, increased significantly to \$45.4 million (\$0.30 per unit, basic) from \$661,000 (\$0.01 per unit, basic) for the same period in 2009.

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

Calculation of Funds From Operations:	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
(thousands)				
Cash flow from operating activities	\$ 107,058	\$ 101,122	\$ 264,133	\$ 181,683
Asset retirement expenditures	2,453	3,018	4,563	5,258
Changes in non-cash working capital	20,557	(2,485)	7,471	20,399
Funds from operations	\$ 130,068	\$ 101,655	\$ 276,167	\$ 207,340

Capital expenditures - Capital expenditures for the three months ended June 30, 2010 were \$316.9 million, consisting of \$68.6 million spent on exploration and development activities and net property acquisitions of \$248.3 million. For the same period in 2009, capital expenditures were \$41.5 million, primarily consisting of exploration and development spending. Capital expenditures for the six months ended June 30, 2010 were \$415.6 million, consisting of \$170.4 million spent on exploration and development activities and net property acquisitions of \$245.2 million. For the same period in 2009 capital expenditures were \$120.7 million, consisting of \$98.5 million on exploration and development spending and \$22.2 million on property acquisitions. Our service costs supporting our exploration and development activities have remained stable across the first half of 2010. Although we anticipate this stability to continue into the third quarter of this year, the recent increase in industry activity will inherently drive an increase in the cost of services into 2011. Bonavista will continue to focus on maintaining similar long-term relationships with service providers in specific operating areas where we have remained active in the past, and will stay active in the future.

Liquidity and capital resources - As at June 30, 2010, long-term debt including working capital (excluding associated assets and liabilities from financial instrument contracts and their related tax impact) was \$999.9 million with a debt to 2010 annualized funds from operations ratio of 1.8:1. Bonavista has significant flexibility to finance future expansions of its capital programs, through the use of its current funds generated from operations and our bank loan facilities totalling \$1.4 billion, of which \$400.1 million is unused borrowing capability.

Bonavista has two bank loan facilities totalling \$1.4 billion provided by a syndicate of 12 domestic and international banks. Both facilities have a maturity date of August 10, 2011 and may, at the request of the Trust and with the consent of the lenders be extended on an annual basis.

Under the terms of both credit facilities, 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 instrument contracts and marketable securities, 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 instrument contracts and marketable securities, 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 the second quarter of 2010, the Trust entered into an uncommitted master shelf agreement that allows for an aggregate draw of up to US\$125 million in notes at a rate equal to the related US treasury corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. On June 4, 2010 the Trust drew down US\$50 million on the master shelf agreement with a coupon rate of 4.86% and a maturity date of June 4, 2017. Under the terms of the master shelf agreement, the Trust has provided the same significant covenants that exist under the bank credit facilities.

Bonavista has modestly increased its capital budget for 2010 with plans to invest between \$600 and \$630 million on its capital programs within its core regions. This capital budget includes the recently closed acquisition of certain long-life natural gas weighted properties located adjacent to its Whitecourt property in west central Alberta for a purchase price of \$230.4 million. The Trust intends on financing its 2010 capital program with a combination of funds from operations, its recently completed \$177.0 million bought deal financing and to the extent required its existing credit facility. Going forward, the Trust remains committed to the fundamental principle of maintaining financial flexibility and the prudent use of debt.

Unitholders' equity - As at June 30, 2010, Bonavista had 155.0 million equivalent trust units outstanding. This includes 9.4 million exchangeable shares, which are exchangeable into 21.6 million trust units. The exchange ratio in effect at June 30, 2010 for exchangeable shares was 2.30481:1. As at July 29, 2010, Bonavista had 155.2 million equivalent trust units outstanding. This includes 9.4 million exchangeable shares, which are exchangeable into 21.8 million trust units. The exchange ratio in effect at July 29, 2010 for exchangeable shares was 2.32051:1. In addition, Bonavista has 4.5 million trust unit incentive rights outstanding at July 29, 2010, with an average exercise price of \$20.90 per trust unit.

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 main objectives of the Trust is to maintain sustainability, which is defined as maintaining both production and reserves over an extended period of time with a minimum amount of capital. This is accomplished by retaining sufficient funds from operations to replace the reserves that have been produced. With these considerations, for the three months ended June 30, 2010 the Trust declared distributions of \$63.9 million (\$0.48 per unit) compared to \$47.4 million (\$0.48 per unit) in the same period in 2009. For the six months ended June 30, 2010 the Trust declared distributions of \$124.0 million (\$0.96 per unit) compared to \$102.5 million (\$1.04 per unit) in the same period in 2009. 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 instrument contracts and marketable securities, 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 three months ended June 30, 2010, the non-cash charges amounted to \$84.6 million compared to \$101.0 million for the same period in 2009. For the six months ended June 30, 2010, the non-cash charges amounted to \$151.0 million compared to \$173.7 million for the same period in 2009. 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.

Distribution Analysis (thousands)	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Cash flow provided from operating activities	\$ 107,058	\$ 101,122	\$ 264,133	\$ 181,683
Net income	45,449	661	125,183	33,620
Distributions declared	63,860	47,430	123,950	102,504
Excess of cash flow provided from operating activities over distributions declared	43,198	53,692	140,183	79,179
Excess (shortfall) of net income over distributions declared	(18,411)	(46,769)	1,233	(68,884)

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. For 2010, our objective is to distribute up to 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. Our current distribution rate of \$0.16 per unit per month will place us slightly below this targeted level for the year assuming current strip prices are realized.

Quarterly financial information - The following table highlights Bonavista's performance for the eight quarterly periods ending on September 30, 2008 to June 30, 2010:

(\$ thousands, except per unit amounts)	2010		2009				2008	
	June 30	March 31	December 31	September 30	June 30	March 31	December 31	September 30
Production revenues	227,732	253,632	232,870	180,977	166,430	179,146	221,782	354,667
Net income	45,449	79,734	39,647	33,339	661	32,959	129,192	207,594
Net income per unit:								
Basic	0.30	0.54	0.27	0.25	0.01	0.28	1.09	1.77
Diluted	0.30	0.53	0.27	0.25	0.01	0.28	1.09	1.75

Production revenues over the past eight quarters have fluctuated largely due to the volatility of commodity prices and increasing production volumes. Net income in the past eight quarters has fluctuated from a low of \$661,000 in the second quarter of 2009 to a high of \$207.6 million in the third quarter of 2008. These fluctuations are primarily influenced by production volumes, commodity prices, realized and unrealized gains and losses on financial instrument contracts and future income tax recoveries associated with the reduction in corporate income tax rates. Net income increased significantly in the second quarter of 2010 as compared to the second quarter of 2009. The increase in net income in the second quarter of 2010 is largely attributed to higher production volumes and the impact of the unrealized gains on financial instrument contracts as compared to the same period in 2009.

Disclosure controls and procedures - Disclosure controls and procedures have been designed to ensure that information 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 appropriately designed and operating effectively to provide reasonable assurance that material information relating to the issuer is made known to them by others within the Trust.

Internal control over financial reporting - Internal control over financial reporting is a process designed to provide reasonable assurance that all assets are safeguarded, transactions are appropriately authorized and to facilitate the preparation of relevant, reliable and timely information. 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. Management has assessed the effectiveness of Bonavista's internal control over financial reporting as defined by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. Management has concluded that their internal control over financial reporting was effective as of June 30, 2010. There were no material changes to the internal controls over financial reporting during the three months ended June 30, 2010.

Update on SIFT tax and corporate conversion - We anticipate the conversion to a dividend paying corporation at the end of 2010 and the subsequent pursuit of a hybrid business model that is designed to provide our investors a combination of growth and income. We will provide more detailed guidance including targeted growth rates and payout ratios closer to year end. In the interim, we continue to introduce incremental operational and capital efficiencies into our business through cost discipline and the application of new technologies to both heritage assets and recently acquired properties. Over the past few years, we have strategically assembled a robust inventory of growth opportunities that will complement this hybrid business model for many years to come.

International financial reporting standards - On January 1, 2011 International Financial Reporting Standards ("IFRS") will become the generally accepted accounting principles in Canada. The adoption date of January 1, 2011 will require restatement, for comparative purposes, of amounts reported by Bonavista for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. An internal project team assisted by external consultants has been set up to manage the conversion from Canadian GAAP to IFRS. The members of this project team have attended IFRS industry specific seminars and continue to guide the Trust's transition to IFRS. The Trust's auditors have and continue to be involved throughout the process to ensure that the Trust's accounting policies are in accordance with the standards set out by IFRS.

Management has not yet finalized its IFRS accounting policies and as such is unable to quantify the impact on its consolidated financial statement by adopting IFRS. The Trust is currently in the process of evaluating its accounting policy choices and the resulting impact these choices have on the financial statements. Once determined, management will present their recommendations of chosen exemptions available under IFRS 1 to the Audit Committee and the Board of Directors for their review and approval, we expect this to be finalized in the third quarter of 2010.

In July 2009, the International Accounting Standards Board ("IASB") issued amendments to IFRS 1, "First Time Adoption of IFRS" allowing an entity that used full cost accounting under its previous GAAP, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and natural gas assets in the development or production phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. The Trust currently plans to adopt this exemption under IFRS 1. IFRS 1 also provides a number of other optional and mandatory exemptions in certain areas to the general requirement for full retrospective application of IFRS. Management is analyzing the various exemptions available under IFRS 1 and will implement those determined to be the most appropriate for the Trust which at this time are summarized as follows:

- Property, Plant and Equipment ("PP&E") – IFRS 1 provides the option to value the PP&E assets at their deemed cost being the Canadian GAAP net book value assigned to these assets as at the date of transition, January 1, 2010. This amendment is for entities that follow the full cost accounting guidelines under Canadian GAAP that accumulate all oil and natural gas assets into one cost centre. Under IFRS, the Trust's PP&E assets are allocated to cash generating units ("CGU"); the net book value of these assets on the date of transition will be allocated to the CGU's on the basis of either the reserve volumes or value at that point in time.
- Business Combinations – IFRS 1 would allow the Trust to use the IFRS rules from business combinations on a prospective basis rather than restating all business combinations.

The transition from present Canadian GAAP to IFRS on January 1, 2011 is significant and may materially affect our reported financial position and results of operations. At this time, Bonavista has identified the following key differences that will impact its financial statements:

- Exploration and Evaluation ("E&E") expenditures – Upon transition to IFRS, Bonavista will reclassify all E&E expenditures that are currently included in the PP&E balance on the Consolidated Balance Sheet. This will consist of the book value for Bonavista's undeveloped land that relates to exploration properties. E&E assets will not be depleted and must be assessed for impairment when indicators of impairment exist.
- Depletion Expense – Upon transition to IFRS, Bonavista has the option to base the depletion calculation on either proved reserves or proved and probable reserves. Bonavista has not concluded at this time which method will be used for calculating depletion.
- Impairment of PP&E assets – Under IFRS, an impairment test of PP&E must be performed on specific portions of PP&E as opposed to the entire PP&E balance which is currently required under Canadian GAAP through the full cost ceiling test. Impairment calculations will be performed at the cash generating unit level based on reserve values or other estimates of fair value.
- Provisions for Asset Retirement costs – Under IFRS, Bonavista is required to revalue its liability for asset retirement costs at each balance sheet date using a current liability specific discount rate. Under present Canadian GAAP, once recorded, asset retirement obligations are not adjusted for future changes in discount rates.

In addition to accounting policy differences, Bonavista's transition to IFRS is expected to impact internal controls over financial reporting, disclosure controls and procedures, certain business activities and information systems.

- Internal controls over financial reporting ("ICFR") – in conjunction with assessing our accounting policy choices, we will also determine whether any changes will be required for ICFR. This will be an ongoing process throughout 2010 to ensure that all changes in accounting policy include the appropriate controls and procedures for IFRS reporting requirements.

- Disclosure controls and procedures – during this transition period Bonavista will assess its stakeholders' information requirements to ensure that adequate and timely information is provided to meet these needs.
- Business activities – Upon transition to IFRS, management has been cognizant of ensuring that any existing agreements that contain references to Canadian GAAP are modified to allow for IFRS statements.
- Information Systems – Bonavista has tested the accounting system updates required in order to handle IFRS reporting. The updates while not significant are critical to allow for reporting of both Canadian GAAP and IFRS statements in 2010. Certain modifications have also been made to track PP&E and E&E expenditures required for IFRS reporting. Additional modifications may be required as we finalize our accounting policy choices.

OUTLOOK

As we approach our conversion to a dividend paying corporation at the end of 2010, we continue to apply the same proven strategies as we have throughout our entire journey of creating value for our investors. The foundation of this strategy is to consistently exercise cost discipline as we actively pursue low to medium-risk drilling opportunities on our extensive land base within geographically concentrated areas of operations. This strategy also involves a consistent component of strategic and complementary acquisitions where we can crystalize incremental value utilizing in-house technical expertise. Despite our execution of a very active exploration and development program over the past year, the quality and quantity of our drilling inventory continues to flourish. Our timely and prudent approach to capital investment has been very effective in the past and our attention to detail together with our steadfast commitment to adding Unitholder value will continue to provide the foundation for the future success of our organization. Today our efficiency, productivity, and confidence are among the highest level in our twelve year history.

We continue to monitor natural gas fundamentals and remain optimistic that the current North American oversupply situation will ultimately balance itself. With this in mind, and when coupled with the positive drilling and acquisition results year to date, Bonavista has modestly increased its capital spending expectations for 2010 to between \$600 and \$630 million. After consideration of \$280 million in budgeted asset acquisitions, approximately \$320 to \$350 million of our 2010 capital budget will be allocated to expanding our exploration and development program where we expect to drill between 140 and 150 wells. Approximately 75% of our development drilling spending will be focused on utilizing horizontal technology to reduce geological risk and enhance ultimate resource recovery resulting in improved capital efficiencies and profitability. This development strategy has driven production performance ahead of expectations creating the confidence to increase our production forecast for 2010 by approximately 2,000 boe per day. We now anticipate 2010 production volumes to average between 66,500 and 67,500 boe per day.

As always, we will continue to closely monitor the economic climate together with our drilling results and remain flexible to adjust our level of capital spending depending on the circumstances. Despite the dynamic property acquisition activity year to date, there remains an abundance of acquisition opportunities in the market. As a result, we continue to exercise additional diligence when selecting incremental investment opportunities investing only in those projects that will maximize value both in the short and long-term.

We are proud of our accomplishments in the second quarter of 2010 and despite the recent instability in commodity prices, we remain enthusiastic and confident about our future. We would like to thank our employees for their significant effort and their continued perseverance as we position ourselves for the future. We remain confident that our operating philosophy works well in any environment and we will continue to create long-term value for our unitholders. Throughout many business cycles and changes in the business environment, Bonavista has converted adversity into opportunity, pursued counter-cyclical strategies and has emerged an even stronger entity as a result of this approach. With our imminent reorganization back to a corporation at year end, our primary focus of executing a proven strategy that has worked so well for us for nearly thirteen years will remain unchanged. Our team is very committed to this vision.

On behalf of the Board of Directors



Keith A. MacPhail
Chairman and Chief Executive Officer



Jason E. Skehar
President and Chief Operating Officer

July 29, 2010
Calgary, Alberta

BONAVISTA ENERGY TRUST
Consolidated Balance Sheets

(thousands)	June 30, 2010	December 31, 2009
(unaudited)		
Assets:		
Current assets:		
Accounts receivable and prepaids	\$ 127,317	\$ 128,363
Marketable securities	-	6,322
Financial instrument contracts	19,501	5,626
Future income tax asset	-	4,424
	146,818	144,735
Oil and natural gas properties and equipment	3,166,566	2,906,073
Goodwill	41,321	41,321
	\$ 3,354,705	\$ 3,092,129
Liabilities and Unitholders' Equity:		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 160,117	\$ 157,019
Distributions payable	21,343	19,937
Financial instrument contracts	1,740	15,169
Convertible debentures	-	38,093
Future income tax	5,179	1,641
	188,379	231,859
Long-term debt	945,727	832,138
Asset retirement obligations	170,577	160,314
Future income tax	136,750	144,235
Unitholders' equity:		
Unitholders' capital and debenture conversion component	1,720,265	1,531,299
Exchangeable shares	57,358	59,295
Contributed surplus	14,746	13,319
Accumulated earnings	120,903	119,670
	1,913,272	1,723,583
	\$ 3,354,705	\$ 3,092,129

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY TRUST

Consolidated Statements of Operations, Comprehensive Income and Accumulated Earnings

(thousands, except per unit amounts)	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
(unaudited)				
Revenues:				
Production	\$ 227,732	\$ 166,430	\$ 481,364	\$ 345,576
Royalties	(35,095)	(20,974)	(75,324)	(53,889)
	192,637	145,456	406,040	291,687
Realized gains on financial instrument contracts	5,065	20,193	5,453	44,477
Unrealized gains (losses) on financial instrument contracts	2,375	(47,949)	26,899	(65,291)
	7,440	(27,756)	32,352	(20,814)
	200,077	117,700	438,392	270,873
Expenses:				
Operating	47,585	48,272	96,738	96,749
Transportation	9,650	8,994	18,449	17,767
General and administrative	5,253	4,193	10,194	8,043
Financing	5,146	2,535	9,945	6,265
Loss (Gain) on marketable securities	223	-	(1,871)	-
Unit-based compensation	2,746	2,823	5,477	5,577
Depreciation, depletion and accretion	89,007	66,749	171,377	132,283
	159,610	133,566	310,309	266,684
Income before taxes	40,467	(15,866)	128,083	4,189
Income taxes (reductions)	(4,982)	(16,527)	2,900	(29,431)
Net income and comprehensive income	45,449	661	125,183	33,620
Accumulated earnings, beginning of period	139,314	208,914	119,670	231,029
Distributions declared	(63,860)	(47,430)	(123,950)	(102,504)
Accumulated earnings, end of period	\$ 120,903	\$ 162,145	\$ 120,903	\$ 162,145
Net income per unit – basic	\$ 0.30	\$ 0.01	\$ 0.83	\$ 0.28
Net income per unit – diluted	\$ 0.29	\$ 0.01	\$ 0.82	\$ 0.28

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY TRUST
Consolidated Statements of Cash Flows

(thousands, except per unit amounts)

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
(unaudited)				
Cash provided by (used in):				
Operating Activities:				
Net income	\$ 45,449	\$ 661	\$ 125,183	\$ 33,620
Items not requiring cash from operations:				
Depreciation, depletion and accretion	89,007	66,749	171,377	132,283
Unit-based compensation	2,746	2,823	5,477	5,577
Unrealized (gains) losses on financial instrument contracts	(2,375)	47,949	(26,899)	65,291
Loss (Gain) on marketable securities	223	-	(1,871)	-
Future income tax (reductions)	(4,982)	(16,527)	2,900	(29,431)
Asset retirement expenditures	(2,453)	(3,018)	(4,563)	(5,258)
Changes in non-cash working capital items	(20,557)	2,485	(7,471)	(20,399)
	107,058	101,122	264,133	181,683
Financing Activities:				
Issuance of equity, net of issue costs	174,184	932	178,888	1,384
Issuance of senior notes	52,625	-	52,625	-
Distributions	(62,565)	(47,375)	(122,544)	(115,400)
Changes in long-term debt	87,687	(1,405)	60,559	70,202
Repayment of convertible debentures	(38,567)	(6,586)	(38,567)	(6,586)
Changes in non-cash working capital items	(687)	(765)	185	(486)
	212,677	(55,199)	131,146	(50,886)
Investing Activities:				
Exploration and development	(68,557)	(41,350)	(170,430)	(98,498)
Property acquisitions	(254,686)	(128)	(250,728)	(22,225)
Property dispositions	7,001	-	6,256	-
Proceeds on sale of marketable securities	3,515	-	8,193	-
Changes in non-cash working capital items	(7,008)	(4,445)	11,430	(10,074)
	(319,735)	(45,923)	(395,279)	(130,797)
Change in cash	-	-	-	-
Cash, beginning of period	-	-	-	-
Cash, end of period	\$ -	\$ -	\$ -	\$ -

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY TRUST

Notes to Consolidated Financial Statements

For the three and six months ended June 30, 2010 (unaudited)

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 7) 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:

The interim consolidated statements of the Trust have been prepared by management in accordance with generally accepted accounting policies in Canada. The unaudited interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2009. The interim consolidated financial statement note disclosures do not include all of those required by Canadian generally accepted accounting principles ("GAAP") applicable for annual financial statements. Accordingly, the interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes hereto as at and for the year ended December 31, 2009.

2. 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 another director of NuVista is also an officer of Bonavista.

For the three months ended June 30, 2010, no management fees, other than standard industry overhead recoveries, were charged by NuVista for our jointly owned partnership (2009 - \$337,500). For the six months ended June 30, 2010, no management fees, other than standard industry overhead recoveries, were charged by NuVista for our jointly owned partnership (2009 - \$675,000). As at June 30, 2010, the amount payable to NuVista was \$499,000 (2009 - \$215,000).

3. 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 \$787.2 million (2009 - \$753.5 million) which will be incurred over the next 51 years. The majority of the costs will be incurred between 2011 and 2038. A credit-adjusted risk-free rate of 7.5% (2009 - 7.5%) and an inflation rate of 2% (2009 - 2%) were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations for the six months ended June 30, 2010 is provided below:

	Amount
(thousands)	
Balance, December 31, 2009	\$ 160,314
Accretion expense	5,767
Liabilities incurred	2,260
Liabilities acquired	6,799
Liabilities settled	(4,563)
Balance, June 30, 2010	\$ 170,577

4. Property acquisition:

On May 31, 2010 the Trust acquired certain long-life natural gas weighted properties located in west central Alberta for a cash purchase price of approximately \$230.4 million.

5. Long-term debt:

	June 30, 2010	December 31, 2009
Long-Term Debt		
(thousands)		
Bank credit facilities	\$ 892,697	\$ 832,138
Senior unsecured notes	53,030	-
Balance, end of period	\$ 945,727	\$ 832,138

a) Bank credit facilities:

The Trust has two bank credit facilities totaling \$1.4 billion with a syndicate of chartered banks. These combined facilities are unsecured, covenant-based, extendible revolving facilities and include a \$50 million working capital facility. The facilities provide 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 facilities are revolving credit and may, at the request of the Trust with the consent of the lenders, be extended on an annual basis. The facilities have a maturity of August 10, 2011 with no principal payments required until then. There is 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 bank credit facilities, 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 instrument contracts and marketable securities, 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 instrument contracts and marketable securities, 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 six months ended June 30, 2010 include interest on long-term debt of \$8.6 million (2009 - \$4.7 million) and convertible debentures of \$1.3 million (2009 - \$1.5 million). For the six months ended June 30, 2010, Bonavista paid cash interest of \$9.8 million (2009 - \$6.8 million). Our effective interest rate for period ending June 30, 2010 was approximately 2.3% (2009 - 1.1%).

b) Senior unsecured notes issued under a master shelf agreement:

In the second quarter of 2010, the Trust entered into an uncommitted master shelf agreement that allows for an aggregate draw of up to US\$125 million in notes at a rate equal to the related US treasuries corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. On June 4, 2010 the Trust drew down US\$50 million on the master shelf agreement with a coupon rate of 4.86% and a maturity date of June 4, 2017. Under the terms of the master shelf agreement, the Trust has provided the same significant covenants that exist under the bank credit facilities.

6. Convertible debentures:

On June 30, 2010 the 6.75% convertible debentures with a conversion price of \$29.00 matured and were cash settled. 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 \$2.8 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 June 30, 2010:

	Debt Component	Equity Component
(thousands)		
Balance, December 31, 2009	\$ 38,093	\$ 808
Accretion	285	-
Amortization of issue expenses	189	-
Repayment of convertible debenture on maturity	(38,567)	(808)
Balance, June 30, 2010	\$ -	\$ -

7. 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, 2009	124,604	\$ 1,530,491
Issued for cash	7,500	177,000
Issued on property acquisition	28	675
Issued on conversion of exchangeable shares	713	1,937
Issued upon exercise of trust unit incentive rights	541	11,094
Conversion of restricted trust units	9	-
Issue costs, net of future tax benefit	-	(6,783)
Unit-based compensation	-	5,851
Balance, June 30, 2010	133,395	\$ 1,720,265

(ii) Contributed surplus:

	Amount
(thousands)	
Balance, December 31, 2009	\$ 13,319
Unit-based compensation expense	5,477
Unit-based compensation capitalized	993
Exercise of trust unit incentive rights and conversion of restricted trust units	(5,851)
Adjustment to equity component of debenture on repayment	808
Balance, June 30, 2010	\$ 14,746

(iii) Exchangeable shares:

	Number	Amount
(thousands)		
Balance, December 31, 2009	9,707	\$ 59,295
Exchanged for trust units	(317)	(1,937)
Balance, June 30, 2010	9,390	57,358
Exchange ratio, June 30, 2010	2.30481	-
Trust units issuable on exchange	21,641	\$ 57,358

c) Long-term incentive plans:

For the three months ended June 30, 2010 there were 12,200 restricted trust units granted and 129,000 trust unit incentive rights issued with an average exercise price of \$23.63 per trust unit and an estimated fair value of \$7.93 per trust unit. As at June 30, 2010 there were 241,997 restricted trust units outstanding and 3.8 million trust unit rights outstanding with an average exercise price of \$20.55 per trust unit. 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 rate was 3.5%; volatility of 33%; a forfeiture rate of 10% and an expected life of 4.5 years.

d) 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:

	Three months ended June 30, 2010
(thousands)	
Trust units	131,809
Exchangeable shares converted at the exchange ratio	21,823
Basic equivalent trust units	153,632
Convertible debentures	1,315
Trust unit incentive rights	763
Restricted trust units	242
Diluted equivalent trust units	155,952

For the purposes of calculating net income per trust unit on a diluted basis, the net income has been increased by \$891,000 (2009 - \$1.0 million) with respect to the accretion, amortization and interest expense on the convertible debentures.

8. Financial instruments:

The Trust has exposure to credit 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.

a) Credit risk:

The carrying amount of accounts receivable represents the maximum credit exposure. As at June 30, 2010 the Trust's receivables consisted of \$74.6 million of receivables from crude oil and natural gas marketers which has substantially been collected, subsequent to June 30, 2010, \$27.1 million from joint venture partners of which \$835,000 has been subsequently collected, and \$25.6 million of Crown deposits and prepaid expenses. As at June 30, 2010 the Trust has \$10.1 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 June 30, 2010 and did not provide for any doubtful accounts nor was it required to write-off any receivables during the three months ended June 30, 2010.

b) Commodity price risk:

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 instrument contracts 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 instrument contracts:

As at June 30, 2010, the Trust has hedged by way of costless collars to sell natural gas and crude oil as follows:

Volume		Average Price	Term
35,000	gjs/d	CDN\$4.46 - CDN\$5.89 - AECO	July 1, 2010 - October 31, 2010
20,000	gjs/d	CDN\$4.56 - CDN\$6.12 - AECO	July 1, 2010 - December 31, 2010
5,000	gjs/d	CDN\$4.50 - CDN\$7.24 - AECO	July 1, 2010 - October 31, 2011
10,000	gjs/d	CDN\$5.13 - CDN\$7.75 - AECO	November 1, 2010 - March 31, 2011
10,000	gjs/d	CDN\$5.25 - CDN\$7.20 - AECO	January 1, 2011 - December 31, 2011
5,000	gjs/d	CDN\$5.00 - CDN\$6.50 - AECO	April 1, 2011 - October 31, 2011
9,000	bbls/d	CDN\$68.06 - CDN\$92.83 - WTI	July 1, 2010 - December 31, 2010
1,500	bbls/d	CDN\$75.00 - CDN\$92.68 - WTI	July 1, 2010 - September 30, 2010
1,500	bbls/d	CDN\$75.00 - CDN\$93.58 - WTI	October 1, 2010 - December 31, 2010
4,500	bbls/d	CDN\$79.44 - CDN\$97.94 - WTI	January 1, 2011 - December 31, 2011

As at June 30, 2010, the Trust limited its downside exposure to natural gas prices by entering into option contracts. The Trust has also hedged its exposure to electricity pricing by entering into a swap which determines a fixed price paid throughout the term of the contract. These financial instrument contracts are outlined below:

Volume		Price	Contract	Term
5,000	gjs/d	CDN \$4.50	Purchased Put - AECO	July 1, 2010 - October 31, 2010
10,000	gjs/d	CDN \$6.45	Sold Call - AECO	April 1, 2011 - October 31, 2011
1	mw/h	CDN\$55.00	Swap - AESO	July 1, 2010 - December 31, 2010

Financial instrument contracts 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 June 30, 2010 the fair market value recorded on the consolidated balance sheet for these financial instrument contracts was a net asset of \$17.8 million, compared to a net liability of \$9.5 million as at December 31, 2009. These financial instrument contracts had the following gains and losses reflected in the consolidated statements of operations, comprehensive income and accumulated earnings:

	Three months ended June 30,		Six months ended June 30,	
	2010	2009	2010	2009
Realized gains on financial instrument contracts	\$ 5,065	\$ 20,193	\$ 5,453	\$ 44,477
Unrealized gains (losses) on financial instrument contracts	2,375	(47,949)	26,899	(65,291)
	\$ 7,440	\$(27,756)	\$32,352	\$(20,814)

Bonavista mitigates its risk associated with fluctuations in commodity prices by utilizing financial instrument contracts. A \$0.10 change in the price per thousand cubic feet of natural gas - AECO would have an impact of approximately \$1.0 million on net income for those financial instrument contracts that were in place as at June 30, 2010. A \$1.00 change in the price per barrel of oil - WTI would have an impact of approximately \$1.3 million on net income for those financial instrument contracts that were in place as at June 30, 2010.

ii) Physical purchase and sale contracts:

As at June 30, 2010, the Trust has entered into physical contracts to sell natural gas as follows:

Volume		Average Price	Term
15,000	gjs/d	CDN\$4.58 - CDN\$6.41 - AECO	July 1, 2010 - October 31, 2010
5,000	gjs/d	CDN\$5.00 - CDN\$6.60 - AECO	July 1, 2010 - December 31, 2010
10,000	gjs/d	CDN\$5.00 - CDN\$7.34 - AECO	November 1, 2010 - March 31, 2011
10,000	gjs/d	CDN\$5.13 - CDN\$6.99 - AECO	January 1, 2011 - December 31, 2011

As at June 30, 2010, the Trust has entered into physical contracts to sell natural gas and to purchase electricity as follows:

Volume		Average Price	Term
5,000	gjs/d	CDN \$5.06 - AECO	July 1, 2010 - December 31, 2010
4	mw/h	CDN\$50.54 - AESO	July 1, 2010 - December 31, 2010
5	mw/h	CDN\$51.44 - AESO	January 1, 2011 - December 31, 2011

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

c) Fair value of financial instruments:

The fair value of financial instrument contracts is determined by the financial intermediary to extinguish all rights or obligations of the financial instrument contracts. As at June 30, 2010, the fair market value of these financial instrument contracts was a net asset of approximately \$17.8 million (2009 - \$9.5 million net liability).

Fair market value of the note payable as at June 30, 2010 is \$53.0 million (2009 - nil), as determined by converting the US\$50 million denominated debt to Canadian dollars using the Bank of Canada noon day rate at June 30, 2010.

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

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Ian S. Brown,

Independent Businessman

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Christopher P. Slubicki,

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Walter C. Yeates,

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Lynda J. Robinson,

Vice President, Human Resources and Administration

Hank R. Spence,

Vice President, Operations

Grant A. Zawalsky,

Corporate Secretary

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BANKERS

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The Toronto-Dominion Bank

Bank of Montreal

Royal Bank of Canada

The Bank of Nova Scotia

National Bank of Canada

Alberta Treasury Branches

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Fortis Capital (Canada) Ltd.

HSBC Bank Canada

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