BONAVISTA ENERGY CORPORATION

ANNUAL REPORT 2015

February 25, 2016

Highlights

	Three months ended December 31			Years ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Financial						
($ thousands, except per share)						
Production revenues	**137,260**	244,612	(44)%	**599,999**	1,106,852	(46)%
Funds from operations(1)	**95,792**	135,845	(29)%	**385,351**	561,105	(31)%
Per share(1) (2)	**0.44**	0.63	(30)%	**1.77**	2.69	(34)%
Dividends declared(3)	**11,664**	42,754	(73)%	**76,762**	164,750	(53)%
Per share	**0.06**	0.21	(71)%	**0.37**	0.84	(56)%
Net income (loss)	**(454,616)**	(60,978)	(646)%	**(751,545)**	4,847	(15,605)%
Per share(4)	**(2.09)**	(0.28)	(646)%	**(3.45)**	0.02	(17,350)%
Adjusted net loss(5)	**(443,793)**	(199,730)	(122)%	**(696,634)**	(136,643)	(410)%
Per share(4)	**(2.04)**	(0.93)	(119)%	**(3.20)**	(0.65)	(392)%
Total assets				**3,523,716**	4,429,402	(20)%
Long-term debt, net of working capital				**1,265,820**	1,032,029	23 %
Long-term debt, net of adjusted working capital(6)				**1,310,663**	1,155,422	13 %
Shareholders' equity				**1,548,266**	2,357,706	(34)%
Capital expenditures:						
Exploration and development	**56,084**	162,155	(65)%	**313,905**	639,560	(51)%
Dispositions, net of acquisitions	**(5,540)**	(87,868)	(94)%	**(30,552)**	(106,777)	(71)%
Weighted average outstanding equivalent shares: (thousands)(4)						
Basic	**218,010**	215,855	1 %	**217,660**	208,719	4 %
Diluted	**220,924**	218,571	1 %	**220,117**	210,957	4 %
Operating						
(boe conversion – 6:1 basis)						
Production:						
Natural gas (mmcf/day)	**325**	359	(9)%	**337**	314	7 %
Natural gas liquids (bbls/day)	**20,804**	18,256	14 %	**17,666**	15,991	10 %
Oil (bbls/day)(7)	**4,934**	7,688	(36)%	**5,445**	8,873	(39)%
Total oil equivalent (boe/day)	**79,862**	85,810	(7)%	**79,288**	77,211	3 %
Product prices:(8)						
Natural gas ($/mcf)	**3.44**	3.87	(11)%	**3.56**	4.27	(17)%
Natural gas liquids ($/bbl)	**19.39**	37.56	(48)%	**23.17**	49.78	(53)%
Oil ($/bbl)(7)	**86.61**	83.76	3 %	**81.23**	80.72	1 %
Operating expenses ($/boe)	**5.85**	7.38	(21)%	**6.60**	8.25	(20)%
General and administrative expenses ($/boe)	**0.97**	1.02	(5)%	**1.12**	1.14	(2)%
Cash costs ($/boe)(9)	**9.80**	10.99	(11)%	**10.70**	12.20	(12)%
Operating netback ($/boe)(10)	**15.76**	19.63	(20)%	**16.16**	22.60	(28)%

NOTES:

(1) Management uses funds from operations to analyze operating performance, dividend coverage and leverage. Funds from operations as presented do not have any standardized meaning prescribed by IFRS 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 IFRS. All references to funds from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures and interest expense. Funds from operations per share is calculated based on the weighted average number of shares outstanding consistent with the calculation of net income per share.

(2) Basic funds from operations per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.

(3) Dividends declared include both cash dividends and common shares issued pursuant to Bonavista's dividend reinvestment plan ("DRIP") and Bonavista's stock dividend program ("SDP"). There were no common shares issued under the DRIP and SDP for the three months ended December 31, 2015 and for the three months ended December 31, 2014. For the year ended December 31, 2015 there were no common shares issued under the DRIP and SDP, 1.7 million common shares were issued under the DRIP and SDP in the comparative year ended December 31, 2014.

(4) Per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.

(5) Amounts have been adjusted to exclude unrealized gains and losses on financial instrument commodity contracts, net of tax.

(6) Amounts have been adjusted to exclude associated assets or liabilities from financial instrument commodity contracts and decommissioning liabilities.

(7) Oil includes light, medium and heavy oil.

(8) Product prices include realized gains and losses on financial instrument commodity contracts.

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

(10) Operating netback equals production revenues including realized gains and losses on financial instrument commodity contracts, less royalties, operating and transportation expenses, calculated on a boe basis.

Highlights (cont'd)			
Years ended December 31	**2015**	2014	% Change
Drilling:			
Gross	**78**	134	(42)%
Net	**70.1**	111.6	(37)%
Land (net acres):			
Undeveloped	**705,610**	816,085	(14)%
Total	**1,929,041**	2,218,776	(13)%
Reserves:(11)			
Proved producing:			
Natural gas (bcf)(12)	**614.9**	662.0	(7)%
Oil and natural gas liquids (mbbls)(13)	**59,592**	59,129	1 %
Total oil equivalent (mboe)	**162,072**	169,456	(4)%
Total proved:			
Natural gas (bcf)(12)	**1,026.0**	1,094.4	(6)%
Oil and natural gas liquids (mbbls)(13)	**91,230**	93,329	(2)%
Total oil equivalent (mboe)	**262,224**	275,729	(5)%
Proved plus probable:			
Natural gas (bcf)(12)	**1,601.7**	1,689.9	(5)%
Oil and natural gas liquids (mbbls)(13)	**139,543**	145,119	(4)%
Total oil equivalent (mboe)	**406,494**	426,768	(5)%
% Proved producing	**40%**	40%	— %
% Proved	**65%**	65%	— %
% Probable	**35%**	35%	— %
Net present value of future cash flow before income taxes ($ millions, proved plus probable):			
0% discount rate	**5,568**	8,845	(37)%
5% discount rate	**3,492**	5,402	(35)%
10% discount rate	**2,412**	3,733	(35)%
15% discount rate	**1,788**	2,783	(36)%
Reserve life index (years):(14)			
Total proved	**9.7**	9.4	3 %
Proved plus probable	**14.1**	13.1	8 %
Reserves (boe per thousand shares - basic):(4)			
Total proved	**1,200**	1,277	(6)%
Proved plus probable	**1,860**	1,977	(6)%
Finding and development costs - proved plus probable ($/boe)(15)	**7.26**	10.86	(33)%
Recycle ratio - proved plus probable(16)	**2.2**	2.1	5 %
Finding, development and acquisition costs - proved plus probable ($/boe)(15)	**9.84**	9.95	(1)%
Recycle ratio - proved plus probable(16)	**1.6**	2.3	(30)%

NOTES:
(11) Working interest reserves are gross reserves prior to deduction of royalties and without including any of Bonavista's royalty interests.
(12) Includes Conventional Natural Gas, Shale Natural Gas and Coal Bed Methane.
(13) Includes Natural Gas Liquids; and Light, Medium, Heavy and Tight Oil.
(14) Calculated based on the amount for the relevant reserve category divided by the production forecast prepared by the independent reserve evaluator (GLJ).
(15) Includes changes in future development costs.
(16) Recycle ratio is calculated using operating netback per boe divided by either finding and development or finding, development and acquisition costs per boe.

Share Trading Statistics	Three months ended December 31, 2015	September 30, 2015	June 30, 2015	March 31, 2015
($ per share, except volume)				
High	4.25	6.80	9.26	8.15
Low	1.60	2.93	6.35	5.62
Close	1.82	3.07	6.79	6.38
Average Daily Volume - Shares	1,210,201	1,047,494	1,050,652	763,522

MESSAGE TO SHAREHOLDERS

Our operational and financial results in 2015 mark another milestone in our goal to re-establish Bonavista as a top decile producer in western Canada. Our cost structure is mirroring that of a decade ago, and our commitment to do more with less has resulted in modest growth in our 2015 production with capital spending less than half of that spent in 2014. This capital program consumed approximately 75% of our funds from operations in 2015 and when added to our dividend commitment, created a sustainable business plan with a total payout ratio of 94%.

Significant improvements in operating and capital efficiencies were realized for the third straight year. Operating costs per boe improved to $6.60 in 2015, a 20% improvement over last year, in addition, fourth quarter operating costs were $5.85 per boe, 21% improvement from the same period in 2014. Our proved and probable finding and development costs declined by 33% to $7.26 per boe when compared to 2014, generating a recycle ratio of 2.2:1. Lastly, our cost to add production from our exploration and development ("E&D") program in 2015 was reduced by approximately ten percent over 2014 and currently, we are adding production between $12,000 and $14,000 per boe per day.

A year ago, with the WTI oil price dropping below US$50.00 per bbl, and propane losing its monetary value, we committed to a total payout ratio being less than forecasted funds from operations for 2015. We delivered on that promise and are committed to that same approach in 2016, given the continued weakness in commodity prices.

Over the past 12 months, both spot natural gas and oil prices have decreased a further 30% to 40%, meaningfully impacting the economics of our key plays. However, strength in the forward curve beyond 2016 enhances those economics with the timing of capital expenditures being key to higher returns. This commodity price environment is also placing further downward pressure on service costs through reductions in capital budgets, while creating acquisition opportunities that are competing favourably with our E&D program. To be successful in the current economic environment, we will remain flexible with our 2016 capital program spending between $145 million and $190 million. We will target the lower end of this range as our base E&D budget, but will be prepared to increase spending on E&D activities should commodity prices strengthen. This flexibility will allow us to reinforce our financial position and/or take advantage of acquisition opportunities that compete favourably with our key play economics. This budget is expected to result in production between 69,000 and 73,000 boe per day. In addition, effective April 1, 2016, our Board of Directors has approved a 67% reduction in the dividend to $0.01 per share per quarter. Using the base E&D budget of $145 million our total payout ratio for 2016 will be approximately 70%, with the remaining funds, approximately $70 million, being applied to our long-term debt.

Operational and financial accomplishments for 2015 include:

- Decreased fourth quarter operating costs by 21% to $5.85 per boe, and annual operating costs by 20% to $6.60 per boe;
- Reduced F&D costs by 33% to $7.26 per boe on a proved plus probable basis, including changes in future development costs ("FDC"), resulting in a recycle ratio of 2.2:1;
- Replaced 91% of production with proved developed producing reserve additions, while spending only 75% of our funds from operations, despite the loss of 10.3 mmboe resulting from the price-related acceleration of economics cutoffs;
- Executed a capital spending program, including acquisitions and divestitures ("A&D") of $283.4 million, a 47% reduction relative to 2014. Exploration and development ("E&D") activities totaled $313.9 million, drilling 78 (70.1 net) wells as compared to $639.6 million in E&D activities drilling 134 (111.6 net) wells in 2014. Dispositions, net of acquisitions were approximately $30.6 million in 2015;

- Generated funds from operations of $95.8 million ($0.44 per share) in the fourth quarter of 2015, a period where realized commodity prices decreased by 23% on a per boe basis and overall production revenues decreased by 44% respectively, when compared to the fourth quarter of 2014;
- Produced 79,862 boe per day in the fourth quarter and 79,288 boe per day in 2015 resulting in three percent growth relative to 2014, notwithstanding a 47% reduction in capital spending;
- Removed 14% of our inactive wells and 20% of our abandoned but unreclaimed wells year-over-year;
- Extended our existing bank credit facility of $600 million to a maturity date of September 10, 2019; and
- Enhanced our commodity hedges resulting in a current portfolio of:
  - Approximately 228,500 gjs per day of natural gas hedged at an average floor price of $3.16 per gj at AECO for 2016 and approximately 121,822 gjs per day at an average floor price of $3.09 per gj for 2017;
  - Approximately 2,700 bbls per day of oil hedged at an average floor price of CDN$78.95 per bbl WTI for 2016 and approximately 250 bbls per day at an average floor price of CDN$90.47 per bbl WTI for 2017; and
  - 1,875 bbls per day of propane hedged at 46% of US WTI pricing for 2016 and 1,000 bbls per day at 40% of US WTI pricing for the first quarter of 2017.
  - Using the midpoint of our production guidance for 2016, Bonavista has approximately 64% of volumes hedged and approximately 23,000 boe per day hedged for 2017.

2015 Acquisition and divestiture highlights:

- Completed 19 property transactions resulting in divestments, net of acquisitions, of approximately 2,200 boe per day of non-core high cost assets. The disposed assets had operating costs in excess of $15.00 per boe.

2015 FOURTH QUARTER AND ANNUAL CORE AREA HIGHLIGHTS

WEST CENTRAL CORE AREA

Our West Central core area draws its strength from a low capital cost structure, resilient economics and consistent results. In 2015, we continued to enhance our execution improving our cost structure in the Glauconite and achieved excellent results from our Morningside drilling program. With over 900,000 net acres and approximately 800 drilling locations in our key plays, our West Central core area represents both reliable, low risk drilling opportunities and promising new key plays. We have built an extensive network of infrastructure including 2,800 kilometers of pipelines and 38 facilities, the majority of which are operated by Bonavista, to support our continued development of this core area.

In 2015, our E&D spending in this core area was $175.5 million, drilling 56 (48.2 net) wells resulting in production of approximately 48,300 boe per day. This stable production rate was achieved while spending only 77% of our operating income for 2015, demonstrating the sustainability of our West Central development program.

Our Glauconite play has been the foundation of this sustainability, while the future potential of our Falher play continues to impress.

Glauconite Natural Gas

We drilled 46 (38.2 net) horizontal wells in 2015 including four (4.0 net) in the fourth quarter resulting in fourth quarter production of approximately 26,200 boe per day.

Our capital costs have improved throughout the year, with the cost to drill and complete a "typical" Glauconite well improving by 25% to $2.3 million when compared to 2014, while operating costs have decreased to below $4.50 per boe in our Hoadley area. Reduced costs and enhanced execution has resulted in annual production addition costs of approximately $12,300 per boe per day, a 10% improvement relative to 2014. The continued strength of the Glauconite play was also demonstrated by the 2015 proved plus probable finding and development costs coming in at a record low $3.74 per boe.

We continue to evolve our completion techniques from nitrogen foam to slick water fracs at Hoadley, resulting in improved well performance. Slick water, when combined with longer reach horizontal wells, has outperformed our conventional type curve by 200% after 12 months of production performance. This is accomplished at a cost equal to approximately 165% of our conventional Glauconite horizontal well.

In 2015, the commissioning of the deep cut processing facility at Rimbey resulted in a potential 30 bbl per mmcf increase in natural gas liquids from the Glauconite play (mostly ethane and propane). Unfortunately though, the challenging price environment for natural gas liquids has resulted in the curtailment of 20% to 60% of our ethane production. Furthermore, with negative propane pricing, we have chosen to redirect some Glauconite production to a Bonavista operated process facility. The benefits of natural gas with higher heat content and a lower operating cost structure at this facility will result in incremental operating income despite the lower recovery rates and production rates realized utilizing this process.

The Glauconite play continues to showcase consistent results with resilient economics that rank amongst the top liquids rich natural gas plays in North America. Our inventory of approximately 370 locations allows for over 13 years of development at our current pace. Our 2016 program entails drilling 16 to 30 (14.2 to 25.5 net) wells.

Spirit River Falher Natural Gas

We drilled eight (8.0 net) Falher wells in 2015 including one (1.0 net) in the fourth quarter.

Our 2015 Morningside Falher program has exceeded our expectations. We drilled six (6.0 net) wells at Morningside and successfully extended the boundaries of the play to the south of our main development area. Our six wells drilled in 2015 demonstrated average production rates of approximately 700 boe per day in their first three months.

Our Morningside Falher play continues to compete equally for capital with our Hoadley Glauconite and Ansell Wilrich plays. With current costs to drill and complete of $2.0 million, annual production addition costs remain less than $8,000 per boe with IRR's in excess of 25% at current commodity prices.

Our 2016 Falher program includes drilling between seven to nine (6.5 to 8.5 net) wells.

DEEP BASIN CORE AREA

In 2015, we continued to expand our foot-print in this liquids-rich natural gas core area. We have established a net land position of approximately 295,000 acres and have increased our inventory through swap and acquisition transactions. We currently have over 300 horizontal drilling locations of which approximately 30% are extended reach. We built additional infrastructure in 2015 by installing a processing facility and a metering station, resulting in further operating cost reductions and incremental egress.

In 2015, we spent $114.8 million on E&D activities drilling 21 (20.9 net) wells. Production has averaged approximately 21,500 boe per day representing a 24% increase from the same period last year despite drilling 34% fewer wells.

Spirit River Wilrich Natural Gas

We drilled 18 (18.0 net) Wilrich wells in 2015 including four (4.0 net) in the fourth quarter, which were our first extended reach (approximately 1.5 mile lateral length) wells.

Improvements to our cost structure have made a significant impact to our economics at Ansell. The commissioning of our new processing facility and metering station in the second half of 2015 will result in operating costs below $3.00 per boe.

The average cost to drill and complete our fourth quarter Ansell wells was $4.9 million, representing an improvement of approximately 14% from the prior year period, despite two of these wells being extended reach horizontal wells. Our annual cost to add production at Ansell is currently $11,000 per boe per day, a 25% reduction from the same period in 2014.

During the second half of 2015, we continued expanding our Wilrich inventory at Ansell through a strategic land swap which added approximately 45 locations, the majority being extended reach wells.

Our 2016 program contemplates drilling between nine and 13 extended reach horizontal wells. We anticipate further economic enhancements driven by improved capital and operating efficiencies as we develop our extended reach program.

STRENGTHS OF BONAVISTA ENERGY CORPORATION

Throughout our nineteen year history, from an initial restructuring in 1997 to create a high growth junior exploration company, through the energy trust phase between July 2003 and December 2010, to a dividend paying corporation, Bonavista has remained committed to the same operating philosophies despite the endless commodity price volatility and uncertainty inherent in the energy sector. We have consistently maintained a high level of profitable investment activity on our asset base. This activity stems from the expertise of our people and their entrepreneurial approach to design profitable development projects with resilience to an unpredictable commodity price environment. Our experienced technical teams have a thorough understanding of our assets and the reservoirs within the Western Canadian Sedimentary Basin as they exercise the discipline and commitment required to deliver long-term value to our shareholders. The core operating and financial principles that guide our people have been with our organization from the beginning and remain solidly intact today.

As a result of our recent successful non-core disposition strategy, our production and development activity is now largely concentrated in two core areas in central Alberta. We create opportunity through undeveloped land purchases, asset swaps, acquisitions and farm-in opportunities in these areas. Specifically over the past five years, technology coupled with North American natural gas supply/demand fundamentals has led to numerous opportunities to reposition the asset portfolio and drastically improve the quality of our development projects. These activities have led to low cost reserve additions and a reliable production base. Today, the predictable production performance and optimized cost structure of our high quality asset base ensures operating netbacks that compete favorably in most operating environments. Furthermore, our assets are predominantly operated by us, providing control over the pace of operations and a direct influence over our operating and capital cost efficiencies.

Our team brings a successful track record of executing reliable development programs with consistency and precision. We continually strive for balance sheet flexibility and remain focused on prudent 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 underpinned with a set of consistent and reliable operating and financial principles. Directors, management and employees also own approximately 10% of the equity of Bonavista, aligning our interests with those of external shareholders.

OUTLOOK

Elevated world oil production and above average North American natural gas inventories will continue to weigh on our industry in 2016. These supply pressures and corresponding low commodity prices have resulted in a 73% drop in total operating U.S. oil and natural gas rigs to approximately 514 from a recent high of 1,931 in September 2014. Reduced drilling activity has impacted production, with North American oil production declining while world oil demand is forecasted to grow in 2016. All of these signals are constructive and support the beginning of a correction to the current imbalance between oil supply and demand.

We are well positioned to succeed through this environment. We are focused on improving our financial flexibility and will continue to rationalize non-core assets and concentrate our capital spending in two core areas. Our key plays in these core areas rank among the best economic performers in western Canada. We remain protected from further commodity price volatility with approximately 83% of our budgeted natural gas revenues and 64% of budgeted total production hedged for 2016 on a boe basis. In addition, our cost structure continues to improve, creating the opportunity to improve capital efficiencies throughout 2016. Lastly, we do not forecast a covenant breach on our long-term debt in 2016.

We intend to be flexible with our 2016 capital budget in light of uncertain commodity prices. This uncertainty will create opportunities with capital allocation and reinvestment timing and as such, we plan capital spending of between $145 and $190 million. This will generate production between 69,000 and 73,000 boe per day, focused on those projects generating at least a 20% IRR in the current commodity price environment. With our revised dividend commitment for 2016, we are targeting a total payout ratio of approximately 70% utilizing our base E&D budget guidance of $145 million, and intend to apply the remaining funds from operations, of approximately $70 million, to improve our balance sheet.

As always, we thank our employees for their tireless dedication and commitment to our vision and our shareholders for their support through these uncertain times. We are confident of our strategies and are backed by a resilient asset base that continues to provide value in this challenging environment.

On behalf of the Board of Directors

Keith A. MacPhail	Jason E. Skehar
Executive Chairman	President and Chief Executive Officer

February 25, 2016
Calgary, Alberta

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 Corporation’s (“Bonavista” or the “Corporation” or "our") audited consolidated financial statements for the year ended December 31, 2015, together with notes related thereto. The following MD&A of the financial condition and results of operations was prepared at, and is dated February 25, 2016.

***Basis of Presentation** - The financial data presented below has been prepared in accordance with the International Financial Reporting Standards ("IFRS").*

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 and plans; (ii) exploration, drilling and development plans; (iii) prospects and drilling inventory and locations; (iv) anticipated production rates; (v) anticipated operating and service costs; (vi) our financial strength; (vii) incremental development opportunities; (viii) total shareholder return; (ix) asset acquisition and disposition plans; (x) growth prospects; (xi) sources of funding, 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.*

***Non-IFRS Measurements** - Within management’s discussion and analysis, references are made to terms commonly used in the oil and natural gas industry. Operating netbacks as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities. Operating netbacks equal production revenues and realized gains and losses on financial instrument commodity contracts, less royalties, operating and transportation 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 this term to analyze operating performance and leverage.*

***Additional IFRS Measurements** - Within management’s discussion and analysis, references are made to terms commonly used in the oil and natural gas industry. Additional IFRS measurements which are non-IFRS measurements that are referenced in the annual financial statements, do not have a standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities. Management uses "funds from operations" and the "ratio of net debt to funds from operations" to analyze operating performance and leverage. 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 IFRS. All references to funds from operations throughout this report are based on cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures and interest expense. Basic funds from operations per share is calculated based on the weighted average number of common shares outstanding in accordance with International Financial Reporting Standards. Net debt is equal to bank debt and senior unsecured notes, net of adjusted working capital. Adjusted working capital excludes the current assets and liabilities from financial instrument commodity contracts. The annualized current quarter funds from operations is calculated as the current quarter funds from operations annualized for the year.*

Operations - Bonavista's exploration and development program for the year ended December 31, 2015 led to the drilling of 78 (70.1 net) wells. Concentrated in the Deep Basin and West Central core areas, drilling for 2015 included 46 (38.2 net) Glauconite wells, 18 (18.0 net) Wilrich wells, 8 (8.0 net) Falher wells, 1 (1.0 net) extended-reach horizontal well in the Blueberry area that targeted the upper Montney formation and 5 (4.9 net) additional wells in miscellaneous zones. Lastly, Bonavista constructed and commissioned our processing facility in our Ansell field to accommodate continued development of the Wilrich formation at a lower cost to process.

Profitability continues to guide Bonavista's exploration and development programs and although capital spending has decreased as a result of the continued erosion of commodity prices, Bonavista's priority is to maintain flexibility to accommodate continued changes in commodity prices, development risk and well performance. As a result, Bonavista is planning to drill between 30.0 net and 50.0 net wells within its core areas in 2016, with a capital budget of between $145 and $190 million.

Reserves - Reserves estimates have been calculated in compliance with National Instrument 51-101 Standards of Disclosure ("NI 51-101"). Of the net present value of the Corporation's reserves, 97% were evaluated by independent third-party engineers, GLJ Petroleum Consultants Ltd. ("GLJ") in their report dated January 25, 2016. The balance of approximately 3% of proved plus probable net present value reserves were evaluated internally and reviewed by GLJ. The reserve estimates contained in the following tables represent Bonavista's gross reserves as at December 31, 2015 and are defined under NI 51-101, as the Corporation's interest before deduction of royalties without including any of the Corporation's royalty interests.

Reserves[1][2]	Natural Gas[3]	Oil[4]	Natural Gas Liquids	Total Reserves[5]
	(mmcf)	(mbbls)	(mbbls)	(mboe)
Proved				
Proved Producing	614,884	14,377	45,215	162,072
Proved Non-producing	19,293	623	1,294	5,132
Proved Undeveloped	391,783	2,975	26,748	95,020
Total Proved	**1,025,960**	**17,974**	**73,256**	**262,224**
Probable	575,745	8,092	40,221	144,270
Proved plus Probable	**1,601,705**	**26,067**	**113,477**	**406,494**
Proved reserve life index (years)[6]				**9.7**
Proved plus Probable reserve life index (years)[6]				**14.1**

(1) Bonavista's working interest reserves are based on the GLJ reserve report dated January 25, 2016, GLJ reserve estimates based on forecast prices and costs as of January 1, 2016.
(2) Amounts may not add due to rounding.
(3) Includes Conventional Natural Gas, Shale Natural Gas and Coal Bed Methane.
(4) Includes Light, Medium, Heavy and Tight Oil.
(5) Boe may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the wellhead.
(6) Calculated based on the amount for the relevant reserve category divided by the 2016 production forecast prepared by GLJ.

Reserve Reconciliation[1]	Proved	Probable	Proved plus Probable
	(mboe)	(mboe)	(mboe)
Balance, December 31, 2014	275,729	151,039	426,768
Extensions and Improved Recovery[2]	**32,354**	**6,790**	**39,143**
Technical revisions	**(5,152)**	**(10,040)**	**(15,192)**
Acquisitions	**3,175**	**1,425**	**4,599**
Dispositions	**(8,133)**	**(5,823)**	**(13,956)**
Economic Factors	**(6,856)**	**880**	**(5,976)**
Production	**(28,893)**	**—**	**(28,893)**
Balance, December 31, 2015	**262,224**	**144,270**	**406,494**

(1) Amounts may not add due to rounding.
(2) Infill Drilling, Improved Recovery and Extensions have been grouped with Extensions and Improved Recovery as per NI 51-101.

Bonavista's 2015 year end proved reserves totaled 262.2 mmboe, a 5% decrease when compared to the 275.7 mmboe at the year end 2014. Proved plus probable reserves decreased by 5% to 406.5 mmboe when compared to 426.8 mmboe at the year end 2014. Bonavista's proved plus probable reserve life index increased by 8% to 14.1 years at the year end of 2015 compared to 13.1 years at the year end 2014.

The following table highlights Bonavista's proved plus probable reserves, proved plus probable finding and the development ("F&D") expenditures, proved plus probable finding, development and acquisition ("FD&A") expenditures and the associated recycle ratios:

Years ended December 31	2015	2014	% Change
Reserves (mboe):			
Proved producing	**162,072**	169,456	(4)%
Total proved	**262,224**	275,729	(5)%
Proved plus probable	**406,494**	426,768	(5)%
Capital expenditures ($ millions):			
Exploration and development	**313.9**	639.6	(51)%
Acquisitions, net of dispositions	**(30.6)**	(106.8)	(71)%
Total capital expenditures[1]	**283.4**	532.8	(47)%
Operating Netback ($/boe):[2]			
Current year	**16.16**	22.60	(28)%
Three-year weighted average	**19.72**	20.37	(3)%

(1) Amounts may not add due to rounding.
(2) Operating netback is calculated using production revenues including realized gains and losses on financial instruments commodity contracts less royalties, transportation and operating costs calculated on a per boe equivalent basis.

Years ended December 31	2015	2014	% Change
Finding and Development Expenditures[5]:			
Proved Producing:			
Change in FDC ($ thousands)	**(339)**	(4,005)	(92)%
Reserves additions (mboe)	**26,252**	49,480	(47)%
F&D costs ($/boe)[3]	**11.94**	12.84	(7)%
F&D recycle ratio[4]	**1.4**	1.8	(22)%
F&D three-year weighted costs ($/boe)[3]	**13.57**	14.90	(9)%
F&D recycle ratio three-year weighted average[4]	**1.5**	1.4	7 %
Total Proved:			
Change in FDC ($ thousands)	**(188,683)**	1,312	(14,481)%
Reserves additions (mboe)	**20,346**	49,455	(59)%
F&D costs ($/boe)[3]	**6.15**	12.96	(53)%
F&D recycle ratio[4]	**2.6**	1.7	53 %
F&D three-year weighted costs ($/boe)[3]	**12.21**	14.70	(17)%
F&D recycle ratio three-year weighted average[4]	**1.6**	1.4	14 %
Proved plus Probable:			
Change in FDC ($ thousands)	**(183,483)**	(19,091)	861 %
Reserves additions (mboe)	**17,975**	57,124	(69)%
F&D costs ($/boe)[3]	**7.26**	10.86	(33)%
F&D recycle ratio[4]	**2.2**	2.1	5 %
F&D three-year weighted costs ($/boe)[3]	**10.65**	12.21	(13)%
F&D recycle ratio three-year weighted average[4]	**1.9**	1.7	12 %
Finding, Development and Acquisition Expenditures[5]:			
Proved Producing:			
Change in FDC ($ thousands)	**4,667**	1,120	317 %
Reserves additions (mboe)	**21,539**	42,753	(50)%
FD&A costs ($/boe)[3]	**13.37**	12.49	7 %
FD&A recycle ratio[4]	**1.2**	1.8	(33)%
FD&A three-year weighted costs ($/boe)[3]	**13.35**	13.43	(1)%
FD&A recycle ratio three-year weighted average[4]	**1.5**	1.5	— %
Total Proved:			
Change in FDC ($ thousands)	**(186,034)**	45,038	(513)%
Reserves additions (mboe)	**15,388**	47,644	(68)%
FD&A costs ($/boe)[3]	**6.32**	12.13	(48)%
FD&A recycle ratio[4]	**2.6**	1.9	37 %
FD&A three-year weighted costs ($/boe)[3]	**12.10**	13.05	(7)%
FD&A recycle ratio three-year weighted average[4]	**1.6**	1.6	— %
Proved plus Probable:			
Change in FDC ($ thousands)	**(198,572)**	28,160	(805)%
Reserves additions (mboe)	**8,618**	56,369	(85)%
FD&A costs ($/boe)[3]	**9.84**	9.95	(1)%
FD&A recycle ratio[4]	**1.6**	2.3	(30)%
FD&A three-year weighted costs ($/boe)[3]	**10.42**	10.71	(3)%
FD&A recycle ratio three-year weighted average[4]	**1.9**	1.9	— %

(3) Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis (6:1).
(4) Recycle ratio is defined as operating netback per boe divided by either F&D or FD&A costs on a per boe basis.
(5) Calculated using gross reserves.

Bonavista demonstrated significant improvements in overall efficiencies in 2015, resulting in proved plus probable F&D cost reductions of 33% to $7.26 per boe from $10.86 per boe in 2014. Bonavista considers its recycle ratio to be an important measure of profitability, delivering a F&D recycle ratio of 2.2:1 for proved plus probable reserves including revisions and changes in future development costs. 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:

	Three months ended December 31			Years ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
($ thousands, except per boe and share amounts where noted)						
Production:						
Natural gas (mmcf/d)	**325**	359	(9)%	**337**	314	7 %
Natural gas liquids (bbls/d)	**20,804**	18,256	14 %	**17,666**	15,991	10 %
Oil (bbls/day)	**4,934**	7,688	(36)%	**5,445**	8,873	(39)%
Total production (boe/d)	**79,862**	85,810	(7)%	**79,288**	77,211	3 %
Product prices:						
Natural gas ($/mmcf)	**3.44**	3.87	(11)%	**3.56**	4.27	(17)%
Natural gas liquids ($/bbl)	**19.39**	37.56	(48)%	**23.17**	49.78	(53)%
Oil ($/bbl)	**86.61**	83.76	3 %	**81.23**	80.72	1 %
Production revenues	**137,260**	244,612	(44)%	**599,999**	1,106,852	(46)%
per boe	**18.68**	30.99	(40)%	**20.73**	39.28	(47)%
Royalties	**11,389**	27,328	(58)%	**54,201**	136,095	(60)%
per boe	**1.55**	3.46	(55)%	**1.87**	4.83	(61)%
% of production revenues	**8.3%**	11.2%	(3)%	**9.0%**	12.3%	(3)%
Operating expenses	**43,000**	58,239	(26)%	**190,889**	232,474	(18)%
per boe	**5.85**	7.38	(21)%	**6.60**	8.25	(20)%
Transportation expenses	**9,023**	9,556	(6)%	**36,500**	36,013	1 %
per boe	**1.23**	1.21	2 %	**1.26**	1.28	(2)%
General and administrative expenses	**7,120**	8,074	(12)%	**32,495**	32,012	2 %
per boe	**0.97**	1.02	(5)%	**1.12**	1.14	(2)%
Share-based compensation expenses	**4,057**	2,608	56 %	**17,157**	20,449	(16)%
per boe	**0.55**	0.33	67 %	**0.59**	0.73	(19)%
Depreciation, depletion, amortization and impairment	**649,232**	404,949	60 %	**1,168,016**	670,510	74 %
per boe	**88.36**	51.29	72 %	**40.36**	23.79	70 %
Net finance costs(1)	**42,099**	39,473	7 %	**166,600**	119,577	39 %
per boe	**5.73**	5.00	15 %	**5.76**	4.24	36 %
Interest expense	**12,860**	11,060	16 %	**49,716**	43,921	13 %
per boe	**1.75**	1.40	25 %	**1.72**	1.56	10 %
Deferred income taxes (recovery)	**(155,253)**	(6,067)	2,459 %	**(204,051)**	34,323	(695)%
per boe	**(21.13)**	(0.77)	2,644 %	**(7.05)**	1.22	(678)%
Net income (loss)	**(454,616)**	(60,978)	(646)%	**(751,545)**	4,847	(15,605)%
per boe	**(61.88)**	(7.72)	(702)%	**(25.97)**	0.17	(15,376)%
per share - basic	**(2.09)**	(0.28)	(646)%	**(3.45)**	0.02	(17,350)%
Dividends declared	**11,664**	42,754	(73)%	**76,762**	164,750	(53)%
per share	**0.06**	0.21	(71)%	**0.37**	0.84	(56)%
Funds from operations(2)	**95,792**	135,845	(29)%	**385,351**	561,105	(31)%
per boe	**13.04**	17.21	(24)%	**13.32**	19.91	(33)%
per share - basic	**0.44**	0.63	(30)%	**1.77**	2.69	(34)%

(1) Includes interest expense.
(2) Additional IFRS measure.

Production - Production volumes for the year ended December 31, 2015 averaged 79,288 boe per day, a 3% increase compared to an average of 77,211 boe per day for the year ended December 31, 2014. The increase in production volumes over the prior year period can be attributed to production additions from the 2014 and 2015 drilling programs and the increase in natural gas liquids yields resulting from a third-party plant expansion commissioned during the third quarter of 2015. This production growth was achieved despite turnaround activity at major third-party facilities during the second quarter of 2015. Natural gas production for the year ended December 31, 2015 was 337 mmcf per day, a 7% increase compared to 314 mmcf per day produced during 2014. Natural gas liquids production was 17,666 bbls per day for the year ended December 31, 2015, a 10% increase when compared to 15,991 bbls per day in the same period in 2014. The increase in natural gas and natural gas liquids production can be attributed to the same factors as described above. The growth in natural gas liquids production on a percentage basis exceeded the increase in natural gas production as a result of the third-party plant expansion commissioned in the third quarter of 2015 which significantly increased natural gas liquids yields in the West Central core area, partially offset by scheduled turnaround activity during the second quarter of 2015 which resulted in the diversion of production volumes to processing facilities with lower liquids recovery efficiencies. Oil production decreased 39% to 5,445 bbls per day for the year ended December 31, 2015 from 8,873 bbls per day in the same period in 2014 due to non-core, oil-weighted dispositions completed in 2014.

Production volumes averaged 79,862 boe per day for the three months ended December 31, 2015, a 7% decrease when compared to an average of 85,810 boe per day for the three months ended December 31, 2014. The decrease in production volumes in the fourth quarter of 2015 over the same period in 2014 is mainly attributed to natural production declines in conjunction with reduced drilling activity as a result of the continued low commodity price environment and our commitment to a sustainable program as illustrated by our total payout ratio of 94% for 2015. The impact of the production decrease was partially mitigated by production growth resulting from the third-party plant expansion discussed above. Natural gas production decreased 9% to 325 mmcf per day for the fourth quarter of 2015 compared to 359 mmcf per day in the same period in 2014. Natural gas liquids production increased 14% to 20,804 bbls per day for the fourth quarter of 2015 from 18,256 bbls per day in the same period in 2014. The third-party plant expansion commissioned in the third quarter of 2015 increased production on a boe basis, resulting in an increase in natural gas liquids production and a reduction to natural gas production due to the significant enhancement of natural gas liquids yields on raw gas production in the West Central core area. Oil production decreased 36% to 4,934 bbls per day for the fourth quarter of 2015 from 7,688 bbls per day in the same period in 2014 as a result of non-core dispositions completed in 2014 and 2015 consisting largely of mature non-core oil assets.

The following table highlights Bonavista's production by product for the three months and years ended December 31:

	Three months ended December 31			Years ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Natural gas (mmcf/day)	**325**	359	(9)%	**337**	314	7 %
Natural gas liquids (bbls/day)	**20,804**	18,256	14 %	**17,666**	15,991	10 %
Oil (bbls/day)	**4,934**	7,688	(36)%	**5,445**	8,873	(39)%
Total oil equivalent (boe/day)	**79,862**	85,810	(7)%	**79,288**	77,211	3 %

The following table summarizes Bonavista's production by core area for the three months and years ended December 31:

	Three months ended December 31			Years ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
West Central area (boe/day)	**51,697**	53,965	(4)%	**48,297**	46,796	3 %
Deep Basin area (boe/day)	**19,684**	20,429	(4)%	**21,459**	17,276	24 %
Other minor areas (boe/day)	**8,481**	11,416	(26)%	**9,532**	13,139	(27)%
Total oil equivalent (boe/day)	**79,862**	85,810	(7)%	**79,288**	77,211	3 %

Bonavista's current production is approximately 72,500 boe per day the composition of which is 69% natural gas, 25% natural gas liquids and 6% light oil.

Production revenues - Production revenues, excluding the impact of financial instrument commodity contracts, for the year ended December 31, 2015 decreased 46% to $600.0 million compared to $1,106.9 million for the year ended December 31, 2014. The decrease in production revenues in 2015 was due to a 47% decrease in commodity prices, partially offset by a 3% increase in production volumes. Similarly, for the three months ended December 31, 2015, production revenues, excluding the impact of financial instrument commodity contracts, were $137.3 million, a 44% decrease from $244.6 million in the comparative 2014 period. The decrease in the fourth quarter of 2015 compared to the same prior year period was directly attributable to a 40% decrease in commodity prices, in addition, to a 7% decrease in production volumes. The decrease in realized commodity pricing for the three months and year ended December 31, 2015 reflects the continued weakness in the global energy industry, induced by ongoing production oversupply which exceeds current global demand. In addition to lower realized natural gas and oil pricing, this supply and demand imbalance has placed continued pressure on natural gas liquids pricing throughout 2015, specifically propane prices which reached historical lows due to oversupply in the North American market.

As a result of prolonged instability in the commodity price environment, natural gas prices, excluding the impact of financial instrument commodity contracts, decreased 38% to $2.89 per mcf compared to $4.65 per mcf in the same period in 2014. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, decreased 55% to $22.09 per bbl for the year ended December 31, 2015, compared to $49.31 per bbl in the same period in 2014. Oil prices, excluding the impact of financial instrument commodity contracts, decreased 42% to $51.39 per bbl for the year ended December 31, 2015, compared to $88.28 per bbl in the same period in 2014. For the three months ended December 31, 2015, natural gas prices, excluding the impact of financial instrument commodity contracts, decreased 33% to $2.68 per mcf compared to $3.99 per mcf in the same period in 2014. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, decreased 49% to $18.79 per bbl for the three months ended December 31, 2015, compared to $37.08 per bbl in the same period of 2014. Oil prices, excluding the impact of financial instrument commodity contracts, decreased 35% to $46.76 per bbl for the three months ended December 31, 2015, compared to $71.71 per bbl in the same period in 2014. The impact of the declining oil prices, which are benchmarked in United States (US) dollars, was partially offset by a weakening of the Canadian (CDN) dollar relative to the US dollar.

The low commodity price environment experienced during 2015 was mitigated by Bonavista's financial instrument commodity contracts. For the year ended December 31, 2015, a gain of $149.2 million was realized on Bonavista's financial instrument commodity contracts compared to a realized loss of $65.2 million in the same period in 2014. Similarly, for the three months ended December 31, 2015, a gain of $41.9 million was realized on Bonavista's financial instrument commodity contracts compared to a realized gain of $5.5 million in the comparative 2014 period.

For the year ended December 31, 2015, natural gas prices, including the impact of financial instrument commodity contracts, decreased 17% to $3.56 per mcf compared to $4.27 per mcf in the same period in 2014. For the year ended December 31, 2015, natural gas liquids prices, including the impact of financial instrument commodity contracts, decreased 53% to $23.17 per bbl, compared to $49.78 per bbl realized in the same period in 2014. Oil prices, including the impact of financial instrument commodity contracts, increased 1% to $81.23 per bbl for the year ended 2015, when compared to $80.72 per bbl realized in the same period in 2014. For the three months ended December 31, 2015, natural gas prices, including the impact of financial instrument contracts, decreased 11% to $3.44 per mcf compared to $3.87 per mcf in the fourth quarter in 2014. For the three months ended December 31, 2015, natural gas liquids prices, including the impact of financial instrument commodity contracts, decreased 48% to $19.39 per bbl, compared to $37.56 per bbl realized in the same period in 2014. Oil prices, including the impact of financial instrument commodity contracts, for the fourth quarter of 2015 were $86.61 per bbl, a 3% increase when compared to $83.76 per bbl realized in the same period in 2014.

The following table highlights Bonavista's production revenues per boe, including realized gains and losses on financial instrument commodity contracts, for the three months and years ended December 31:

	Three months ended December 31		Years ended December 31	
	2015	2014	**2015**	2014
Natural gas ($/mcf):				
Production revenues	**2.68**	3.99	**2.89**	4.65
Realized gains (losses) on financial instrument commodity contracts	**0.76**	(0.12)	**0.67**	(0.38)
	3.44	3.87	**3.56**	4.27
Natural gas liquids ($/bbl):				
Production revenues	**18.79**	37.08	**22.09**	49.31
Realized gains on financial instrument commodity contracts	**0.60**	0.48	**1.08**	0.47
	19.39	37.56	**23.17**	49.78
Oil ($/bbl):				
Production revenues	**46.76**	71.71	**51.39**	88.28
Realized gains (losses) on financial instrument commodity contracts	**39.85**	12.05	**29.84**	(7.56)
	86.61	83.76	**81.23**	80.72
Total ($/boe):				
Production revenues	**18.68**	30.99	**20.73**	39.28
Realized gains (losses) on financial instrument commodity contracts	**5.71**	0.70	**5.15**	(2.31)
	24.39	31.69	**25.88**	36.97

Risk management activities - As part of our financial management strategy, Bonavista has adopted a disciplined commodity price risk management program. Bonavista's risk management program aims to reduce the impact of commodity price volatility and protect funds from operations, protect acquisition and development economics and fund dividend commitments. The Board of Directors has approved a commodity price risk management limit of 70% of forecasted revenues, net of royalties for the subsequent twelve month period and 60% thereafter, provided that no more than 80% of forecasted revenues, net of royalties, from any one product may be hedged, or in the case of electricity, 60% of Bonavista's forecasted consumption. The term of any commodity hedge will be limited to no more than three calendar years subsequent to the current calendar year.

Commodity prices for 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 CDN and US currency. Swaps and costless collars are primarily entered into, which limits Bonavista's exposure to volatility in commodity prices while in the case of costless collars allows for the participation in some of the commodity price increases.

As at December 31, 2015, Bonavista entered into the following costless collars to sell natural gas:

Volume		Average Price	Term
10,000	gjs/d	CDN $3.75 - CDN $4.26 - AECO	January 1, 2016 - March 31, 2016
20,000	gjs/d	CDN $3.69 - CDN $4.04 - AECO	January 1, 2016 - December 31, 2016
15,000	gjs/d	CDN $3.00 - CDN $3.29 - AECO	January 1, 2016 - December 31, 2017
10,000	gjs/d	CDN $3.75 - CDN $4.20 - AECO	January 1, 2017 - December 31, 2017
10,550	gjs/d	US $3.90 - US $4.43 - NYMEX	January 1, 2016 - March 31, 2016

As at December 31, 2015, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
20,000	gjs/d	CDN $3.32	Swap - AECO	January 1, 2016 - December 31, 2016
5,000	gjs/d	CDN $3.81	Swap - AECO	January 1, 2016 - March 31, 2016
10,000	gjs/d	CDN $2.17	Swap - AECO	January 1, 2016 - September 30, 2016
20,000	gjs/d	CDN $3.56	Swap - AECO	January 1, 2016 - December 31, 2016
45,000	gjs/d	CDN $3.00	Swap - AECO	January 1, 2016 - December 31, 2017
10,000	gjs/d	CDN $2.60	Swap - AECO	January 1, 2016 - December 31, 2018
20,000	gjs/d	CDN $2.64	Swap - AECO	April 1, 2016 - October 31, 2016
5,000	gjs/d	CDN $3.08	Swap - AECO	October 1, 2016 - December 31, 2016
20,000	gjs/d	CDN $3.27	Swap - AECO	January 1, 2017 - March 31, 2017
20,000	gjs/d	CDN $3.00	Swap - AECO	April 1, 2017 - October 31, 2017
10,550	gjs/d	US $3.50	Swap - NYMEX	January 1, 2017 - March 31, 2017
10,550	gjs/d	US $(0.47)	Swap - AECO Basis	January 1, 2016 - March 31, 2016
10,550	gjs/d	US $(0.60)	Swap - AECO Basis	April 1, 2016 - December 31, 2018
2,500	bbls/d	US 46.2%	Swap - CNWY PN/WTI	January 1, 2016 - March 31, 2016(1)
1,000	bbls/d	US 40%	Swap - CNWY PN/WTI	April 1, 2016 - March 31, 2017(1)
1,000	bbls/d	US $(3.95)	Swap - WTI-MSW	January 1, 2016 - December 31, 2016
500	bbls/d	US $1.50	Swap - WTI-CRW	February 1, 2016 - March 31, 2016
1,500	bbls/d	CDN $78.87	Swap - WTI	January 1, 2016 - December 31, 2016(2)
500	bbls/d	US $65.00	Swap - WTI	January 1, 2016 - December 31, 2016
500	bbls/d	US $65.25	Swap - WTI	July 1, 2016 - June 30, 2017

(1) Conway propane price as a percentage of WTI.
(2) Includes an extendable feature on 500 bbls/d, which at the discretion of the counterparty would continue the term of the contract to December 31, 2017.

Subsequent to December 31, 2015, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
10,000	gjs/d	CDN $2.43	Swap - AECO	April 1, 2016 - October 31, 2016
10,000	gjs/d	CDN $2.65	Swap - AECO	April 1, 2016 - March 31, 2017
500	bbls/d	CDN $60.42	Swap - WTI	February 1, 2016 - December 31, 2016
500	bbls/d	CDN $65.00	Sold Call - WTI	January 1, 2018 - December 31, 2018
1,000	bbls/d	US 55.9%	Swap - MTB BT/WTI	April 1, 2016 - September 30, 2016

As at December 31, 2015, Bonavista entered into the following contracts to purchase electricity:

Volume		Price	Contract	Term
5	mwh	CDN $51.60	Swap - AESO	January 1, 2016 - December 31, 2016
2	mwh	CDN $48.18	Swap - AESO	January 1, 2017 - December 31, 2017

As at December 31, 2015, the fair market value recorded in the consolidated statement of financial position for these financial instrument commodity contracts was a net asset of $80.5 million compared to a net asset of $153.9 million as at December 31, 2014. Of the $80.5 million net asset balance at December 31, 2015, $63.4 million relates to financial instrument commodity contracts with term dates within one year and $17.1 million relates to financial instrument commodity contracts with term dates beyond one year.

For the year ended December 31, 2015, the financial instrument commodity contracts in place under Bonavista's risk management program resulted in a net gain of $75.8 million, consisting of a realized gain of $149.2 million and an unrealized loss of $73.4 million. The realized gain of $149.2 million consisted of a $82.9 million gain on natural gas commodity derivative contracts, a $7.0 million gain on natural gas liquids commodity derivative contracts and a $59.3 million gain on oil commodity derivative contracts. For the same period in 2014, the financial instrument commodity contracts in place resulted in a net gain of $123.6 million, consisting of a realized loss of $65.2 million and an unrealized gain of $188.8 million. The realized loss of $65.2 million consisted of a $43.5 million loss on natural gas commodity derivative contracts and a $24.5 million loss on oil commodity derivative contracts offset by a $2.8 million gain on natural gas liquids commodity derivative contracts.

For the three months ended December 31, 2015, the financial instrument commodity contracts in place under Bonavista's risk management program resulted in a net gain of $27.7 million, consisting of a realized gain of $41.9 million and an unrealized loss of $14.2 million. The realized gain of $41.9 million consisted of a $22.7 million gain on natural gas commodity derivative contracts, a $1.1 million gain on natural gas liquids commodity derivative contracts and a $18.1 million gain on oil commodity derivative contracts. For the same period in 2014, the financial instrument commodity contracts in place resulted in a net gain of $190.6 million, consisting of a realized gain of $5.5 million and an unrealized gain of $185.1 million. The realized gain of $5.5 million consisted of a $8.5 million gain on oil commodity derivative contracts and a $0.8 million gain on natural gas liquids derivative contracts offset by a $3.8 million loss on natural gas commodity derivative contracts .

The following table highlights Bonavista's realized and unrealized gains and losses on financial instrument commodity contracts for the three months and years ended December 31:

	Three months ended December 31		Years ended December 31	
	2015	2014	**2015**	2014
($ thousands)				
Natural gas	**22,688**	(3,845)	**82,882**	(43,517)
Natural gas liquids	**1,145**	814	**6,964**	2,756
Oil	**18,091**	8,521	**59,307**	(24,471)
Realized gains (losses) on financial instrument commodity contracts	**41,924**	5,490	**149,153**	(65,232)
Unrealized gains (losses) on financial instrument commodity contracts	**(14,231)**	185,148	**(73,370)**	188,803
	27,693	190,638	**75,783**	123,571

Bonavista's financial instrument commodity contracts are sensitive to commodity price volatility. The change in fair value for those natural gas financial instrument commodity contracts in place at December 31, 2015 due to a $0.10 change in the price per thousand cubic feet of natural gas at AECO, would have impacted net income (loss) by approximately $7.9 million compared to $10.4 million in the same period in 2014. The change in fair value for those oil financial instrument commodity contracts in place at December 31, 2015 due to a $1.00 change in the price per barrel of oil at WTI would have impacted net income (loss) by approximately $1.0 million compared to $2.1 million in the same period in 2014.

In addition to these financial instrument commodity contracts in place, Bonavista also entered into the following physical contracts to sell natural gas as at December 31, 2015:

Volume		Price	Term
50,000	gjs/d	CDN $3.42	January 1, 2016 - December 31, 2016(1)
10,000	gjs/d	CDN $2.52	April 1, 2016 - June 30, 2016(2)
10,000	gjs/d	CDN $2.96	April 1, 2016 - October 31, 2016(2)
20,000	gjs/d	CDN $3.23	January 1, 2017 - December 31, 2017(2)(3)

(1) Includes an extendable feature which at the discretion of the counterparty would continue the term of the contract to December 31, 2017.
(2) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 10,000 gjs/d on the last trade date of each month for the duration of the contract.
(3) Includes an extendable feature which at the discretion of the counterparty would continue the term of the contract on 10,000 gjs/d to December 31, 2018.

Bonavista is exposed to foreign currency fluctuations as oil and natural gas prices received are referenced to US dollar denominated prices. Bonavista has mitigated some of this foreign exchange risk by entering into fixed CDN dollar oil and natural gas swaps and collars as outlined in the commodity price risk section above. In addition, Bonavista has US dollar denominated senior unsecured notes and interest obligations of which future cash repayments are directly impacted by the CDN dollar to the US dollar exchange rate.

To fix the foreign exchange rate on a portion of the US dollar denominated senior unsecured notes, Bonavista has entered into the following contracts to purchase US dollars at predetermined rates on settlement dates that coincide with Bonavista's US dollar debt repayment commitments.

Settlement date	Contract	Notional US$	CDN$/US$
June 6, 2016	US$ purchased forward	$12,500,000	1.2220
June 5, 2017	US$ purchased forward	$12,500,000	1.2234
November 2, 2017	US$ purchased forward	$ 60,000,000	1.1089
November 2, 2020	US$ purchased forward	$160,000,000	1.1494
October 25, 2021	US$ purchased forward	$150,000,000	1.2297
November 2, 2022	US$ purchased forward	$16,500,000	0.9950

The fair value recorded on the consolidated statement of financial position for these financial instrument contracts as at December 31, 2015 was a net asset of $70.8 million of which $2.0 million relates to a financial instrument contract with a term date within one year and $68.8 million relates to financial instrument contracts with term dates beyond one year. In comparison the fair value of those financial instrument contracts in place as at December 31, 2014 was a long-term asset of $16.0 million.

For the year ended December 31, 2015, an unrealized gain of $54.7 million was recorded in finance income on the consolidated statement of income (loss) and comprehensive income (loss), compared to an unrealized gain of $8.0 million in the same period in 2014. The unrealized gain for the year ended December 31, 2015, resulted from the weakening of the CDN dollar relative to the US dollar, which as at December 31, 2015 was $1.384 CDN$/US$ compared to the 2014 year-end exchange rate of $1.1601 CDN$/US$. A $0.01 change in the CDN$/US$ exchange rate at December 31, 2015 would have had an impact of approximately $0.2 million on net loss for the year ending December 31, 2015.

For the three months ended December 31, 2015, an unrealized gain of $9.1 million was recorded in finance income on the consolidated statement of income (loss) and comprehensive income (loss), compared to an unrealized gain of $3.7 million in the same period in 2014. The unrealized gain for the three months ended December 31, 2015, resulted from the weakening of the CDN dollar relative to the US dollar, which as at December 31, 2015 was $1.384 CDN$/US$ compared to the rate of $1.3345 CDN$/US$ as at September 30, 2015.

Royalties - Royalties for the year ended December 31, 2015 decreased 60% to $54.2 million from $136.1 million in the same period in 2014. Royalties as a percentage of total production revenues were 9.0% for the year ended December 31, 2015 compared to 12.3% of total production revenues in the comparative 2014 period. The significant decrease in royalties on an absolute basis and as a percentage of production revenues for the year ended December 31, 2015, was due to a 46% decrease in production revenues in addition to a change in revenue composition as 59% of production revenues for the year ended December 31, 2015 is comprised of natural gas which attracts lower royalty rates, compared to 48% in the same prior year period.

Natural gas royalties as a percentage of natural gas production revenues for the year ended December 31, 2015 were 5.5% compared to 8.3% for the year ended December 31, 2014, reflecting the lower reference prices used in the calculation of natural gas crown royalty obligations. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the year ended December 31, 2015 were 16.6% compared to 17.5% in the same period in 2014. Natural gas liquids royalties were lower as a percentage of natural gas liquids revenues for the year ended 2015 due to changes to the Alberta natural gas liquids reference price structure effective July 1, 2014, partially offset by a change in the composition of Bonavista's natural gas liquids revenue to a pentane and condensate weighting which attracted higher royalty rates. Oil royalties as a percentage of oil production revenues for the year ended

December 31, 2015 were lower at 10.9% compared to 14.4% for the year ended December 31, 2014, reflecting the impact of decreased par prices used in the calculation of oil crown royalty obligations.

For the three months ended December 31, 2015 royalties decreased 58% to $11.4 million from $27.3 million in the same period in 2014. Royalties as a percentage of total production revenues were 8.3% for the three months ended December 31, 2015 compared to 11.2% in the comparative 2014 period. The decrease in royalties on an absolute basis and as a percentage of production revenues was due in large part to a 44% decrease in production revenues as well as the composition of production revenues. For the three months ended December 31, 2015, 58% of Bonavista's production revenues were comprised of natural gas compared to 54% in the same 2014 period resulting in a reduced overall corporate royalty rate.

Natural gas royalties as a percentage of natural gas production revenues for the three months ended December 31, 2015 were 4.7% compared to 6.7% for the fourth quarter of 2014, reflecting the reduced royalty obligation resulting from lower references prices used in the calculation of natural gas crown royalties. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the three months ended December 31, 2015 were 15.0% compared to 17.6% in the same period in 2014. Natural gas liquids royalties were lower as a percentage of natural gas liquids revenues in the fourth quarter of 2015, primarily as a result of the higher weighting to ethane which attracts a lower royalty rate. Oil royalties as a percentage of oil production revenues for the three months ended December 31, 2015 decreased to 10.4% compared to 14.9% for the three months ended December 31, 2014, reflecting the impact of decreased par prices used in the calculation of oil crown royalty obligations.

The following table highlights Bonavista's royalties by product for the three months and years ended December 31:

	Three months ended December 31			Years ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Natural gas ($/mcf):						
Royalties	**0.13**	0.27	(52)%	**0.16**	0.39	(59)%
% of production revenues(1)	**4.7%**	6.7%	(2.0)%	**5.5%**	8.3%	(2.8)%
Natural gas liquids ($/bbl):						
Royalties	**2.82**	6.52	(57)%	**3.66**	8.64	(58)%
% of production revenues(1)	**15.0%**	17.6%	(2.6)%	**16.6%**	17.5%	(0.9)%
Oil ($/bbl):						
Royalties	**4.85**	10.67	(55)%	**5.63**	12.72	(56)%
% of production revenues(1)	**10.4%**	14.9%	(4.5)%	**10.9%**	14.4%	(3.5)%
Total ($/boe):						
Royalties	**1.55**	3.46	(55)%	**1.87**	4.83	(61)%
% of production revenues(1)	**8.3%**	11.2%	(2.9)%	**9.0%**	12.3%	(3.3)%

(1) % of production revenues excludes gains and losses on financial instrument commodity contracts.

On January 29, 2016, the Alberta provincial government announced the key highlights of a proposed Modernized Royalty Framework ("MRF") that will be effective on January 1, 2017. These highlights include; a simplified system of providing economic incentives for the efficient development of Alberta's oil and natural gas resources; no changes to the royalty structure on existing wells drilled prior to 2017 for a 10 year period; MRF will apply to all wells drilled after 2017 and will encompass different royalty structure under pre and post payout. Pre-payout, companies will pay a flat 5% royalty until the well has paid out on a revenue minus cost structure. There are two royalty phases under post-payout. The first phase, "mid-life", royalties are tied to commodity prices. Under this phase royalties will be more than the 5% flat rate and are intended on average to yield the same internal rates of return that exist under the current royalty system. The second phase, "maturity" will go into effect once a well hits 20 bbls per day for oil and 200 mcf per day for natural gas. Under this phase the royalty rates will move to a sliding scale with a 5% minimum acknowledging that lower rate older wells have higher units costs. While the Alberta government has not released all the details of the MRF, the changes are not currently expected to have a significant impact on our operations.

Operating expenses - Operating expenses for the year ended December 31, 2015 decreased 18% to $190.9 million compared to $232.5 million for the year ended December 31, 2014. Similarly, operating expenses on a per boe basis decreased 20% to $6.60 per boe for the year ended December 31, 2015 compared to $8.25 per boe in the same prior year period. Although production volumes for the year ended December 31, 2015 increased 3% when compared to the same 2014 period, significant decreases in operating expenses on an absolute and per boe basis were realized. These reductions were achieved through the continued focus of allocating Bonavista's capital to the lower operating cost structures in the West Central and Deep Basin core areas as well as expenditure reduction initiatives and ongoing cost control efforts including decreases in supplier service costs. In addition, significant cost savings were realized as a result of the Ansell gas plant commissioned in the third quarter of 2015 and the disposition of higher cost non-core assets throughout 2015.

Operating expenses for the three months ended December 31, 2015 decreased 26% to $43.0 million compared to $58.2 million in the same period in 2014. Operating expenses on a per boe basis decreased 21% to $5.85 per boe for the three months ended December 31, 2015 compared to $7.38 per boe in the same period in 2014. Bonavista's focus on asset concentration, operating cost efficiencies and cost control within its core areas as well as the cost savings realized through the newly commissioned Ansell gas plant, resulted in the significant reduction in operating expenditures on an absolute and per boe basis.

The following table highlights Bonavista's operating expenses by product for the three months and years ended December 31:

	Three months ended December 31			Years ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Natural gas ($/mcf)	**0.85**	1.05	(19)%	**0.98**	1.16	(16)%
Natural gas liquids ($/bbl)	**5.79**	9.31	(38)%	**7.18**	10.16	(29)%
Oil ($/bbl)	**11.01**	11.39	(3)%	**11.10**	12.27	(10)%
Total ($/boe)	**5.85**	7.38	(21)%	**6.60**	8.25	(20)%

Transportation expenses - Transportation expenses for the year ended December 31, 2015 were $36.5 million, a marginal increase from $36.0 million for the year ended December 31, 2014. Conversely, transportation expenses on a per boe basis were 2% lower at $1.26 per boe for the year ended December 31, 2015 compared to $1.28 per boe in the same prior period year. The increase in absolute transportation costs for the year ended December 31, 2015 was due to the increase in natural gas and natural gas liquids production compared to the prior year, offset by the disposition of oil-weighted, non-core properties throughout 2014 which carried higher transportation rates. Transportation expenses on a per boe basis were impacted by Bonavista's increased natural gas and natural gas liquids production profile which carry lower transportation costs per boe, as well as additional natural gas liquids volumes resulting from a third-party plant expansion commissioned in the third quarter of 2015 which have limited transportation costs.

Transportation expenses for the three months ended December 31, 2015 decreased 6% to $9.0 million compared to $9.6 million in the same period in 2014, largely due to the 7% decrease in production volumes. Transportation expenses on a per boe basis for the three months ended December 31, 2015 increased 2% to $1.23 per boe from $1.21 per boe for the comparative 2014 period. The increase in transportation expenses on a per boe basis compared to the same prior year period resulted from excess firm capacity in the fourth quarter of 2015, partially offset by the impact of increased natural gas liquids volumes with limited transportation costs, in the West Central core area due to the commissioning of a third-party plant expansion.

The following table highlights Bonavista’s transportation costs by product for the three months and years ended December 31:

	Three months ended December 31			Years ended December 31		
	2015	2014	% Change	**2015**	2014	% Change
Natural gas ($/mcf)	**0.25**	0.22	14 %	**0.24**	0.24	— %
Natural gas liquids ($/bbl)	**0.34**	0.67	(49)%	**0.48**	0.59	(19)%
Oil ($/bbl)	**1.85**	1.53	21 %	**1.90**	1.71	11 %
Total ($/boe)	**1.23**	1.21	2 %	**1.26**	1.28	(2)%

General and administrative expenses - General and administrative expenses, after overhead recoveries, increased 2% to $32.5 million for the year ended December 31, 2015 compared to $32.0 million for the year ended December 31, 2014. The increase in absolute general and administrative expenses was impacted by one-time compensation costs in relation to reductions in staffing levels, in addition to lower capital overhead recoveries associated with decreased capital spending for the year ended December 31, 2015 relative to the comparative 2014 period. On a per boe basis, general and administrative expenses decreased to $1.12 per boe for the year ended December 31, 2015 from $1.14 per boe for the same period in 2014 due mostly to a 3% increase in production volumes.

General and administrative expenses, after overhead recoveries, was $7.1 million for the fourth quarter ended December 31, 2015, a 12% decrease when compared to $8.1 million in the same period in 2014. On a per boe basis, general and administration expenses decreased 5% to $0.97 per boe for the three months ended December 31, 2015 compared to $1.02 per boe in the same period in 2014. The decrease in general and administrative expenses on both an absolute and per boe basis is due to a decrease in cost structure and reduced discretionary spending.

Share-based compensation - On January 1, 2015, Bonavista adopted a Performance Incentive Award Plan for certain directors, officers, employees and eligible consultants. The performance incentive awards vest thirty-nine months from the date of grant and the number of notional common shares issued for each performance incentive award granted is subject to a corporate performance multiplier. Share-based compensation expense, recognized in connection with Bonavista's option, incentive and performance incentive award plans ("long-term incentive plans"), for the year ended 2015 was $17.2 million compared to $20.4 million recognized in the same period in 2014. For the year ended December 31, 2015, $1.7 million of share-based compensation expense was capitalized to property, plant and equipment compared to $2.2 million in the same period in 2014. Share-based compensation expense was lower for the year ended December 31, 2015, due to lower valued incentive awards being expensed in 2015 as compared to the same period in 2014, along with grant forfeitures which was partially offset by an acceleration of expense recognized for options voluntarily surrendered by Bonavista's employees throughout 2015.

Share-based compensation expense recognized in connection with Bonavista's long-term incentive plans was $4.1 million for the three months ended December 31, 2015 compared to $2.6 million recognized in the comparative 2014 period. For the three months ended December 31, 2015, $0.5 million of share-based compensation expense was capitalized to property, plant and equipment compared to $0.3 million in the same period in 2014.

The following table highlights Bonavista’s share-based compensation expense recognized for the three months and years ended December 31:

	Three months ended December 31		Years ended December 31	
	2015	2014	**2015**	2014
($ thousands, except for per boe amounts)				
Share-based compensation expense	**4,057**	2,608	**17,157**	20,449
Share-based compensation expense per boe	**0.55**	0.33	**0.59**	0.73

Depletion, depreciation, amortization and impairment - For the year ended December 31, 2015, depletion, depreciation, amortization and impairment increased 74% to $1,168.0 million, compared to $670.5 million recognized during the same period in 2014. The significant increase was a result of $812.0 million in impairment charges recorded for the year ended December 31, 2015 (December 31, 2014 - $300.0 million). On a per boe basis, depletion, depreciation, amortization and impairment increased 70% to $40.36 per boe for the year ended December 31, 2015 compared to $23.79 per boe in the same period in 2014 for similar reasons as discussed above.

For the three months ended December 31, 2015, depletion, depreciation, amortization and impairment increased 60% to $649.2 million from $404.9 million in the same period in 2014. On a per boe basis, depletion, depreciation, amortization and impairment increased 72% to $88.36 per boe for the three months ended December 31, 2015 compared to $51.29 per boe in the same period in 2014. The increase in depletion, depreciation, amortization and impairment is largely due to the impact of the impairment charge discussed above, offset slightly by a 7% decrease in production volumes during the fourth quarter of 2015.

The following table represents the impact of the impairment charges in each of our areas due to the significant and sustained decline in the commodity price environment for the three months and years ended 2015 and 2014.

	Three months ended December 31		Years ended December 31	
	2015	2014	**2015**	2014
($ thousands)				
West Central Area				
Central Alberta CGU	**204,000**	—	**364,000**	105,000
South Central Alberta CGU	**28,000**	—	**105,000**	—
Deep Basin Area				
North Central Alberta CGU	**194,000**	—	**194,000**	—
Other Area				
British Columbia CGU	**83,000**	—	**83,000**	85,000
Southern Alberta CGU	**5,000**	—	**18,000**	60,000
Eastern Alberta CGU	**48,000**	—	**48,000**	50,000
Total Impairment	**562,000**	—	**812,000**	300,000

Excluding the impact of the impairment charge recognized for the year ended December 31, 2015, Bonavista's depreciation, depletion and amortization expenses decreased 4% to $356.0 million from $370.5 million for the same period in 2014, due to a reduction in the carrying value of oil and natural gas properties as a result of the impairment charges recognized for the year ended December 31, 2014 despite a 3% increase in production volumes. On a per boe basis the average expense recognized for depletion, depreciation and amortization for the year ended December 31, 2015, was $12.30 per boe compared to $13.15 per boe in the same period in 2014.

For the three months ended December 31, 2015, depreciation, depletion and amortization expenses, excluding the impact of the impairment charge, decreased 17% to $86.9 million compared to $104.9 million for the three months ended December 31, 2014, due to a 7% decrease in production volumes and the impact of the 2014 impairment charge as discussed above. On a per boe basis the average expense recognized for depletion, depreciation and amortization for the three months ended December 31, 2015, decreased 11% to $11.83 per boe from $13.29 per boe in the same period in 2014.

Net financing costs - Net financing costs increased to $166.6 million for the year ended December 31, 2015, from net financing costs of $119.6 million in the comparative 2014 period. The increase is largely attributable to an increase in unrealized foreign exchange losses associated with the revaluation of Bonavista's US dollar denominated senior unsecured notes, partially offset by unrealized gains on the fair value of foreign exchange financial instrument contracts. Similarly, for the year ended December 31, 2015, net financing costs on a per boe basis increased to $5.76 per boe compared to net financing costs of $4.24 per boe in the same period in 2014, for the same reasons as stated above. Net financing costs, excluding non-cash amounts, increased 13% to $49.7 million for the year ended December 31, 2015, compared to $43.9 million for the year ended December 31, 2014. The increase in net financing costs, excluding non-cash amounts, was due to higher interest costs associated with the translation of US dollar interest associated with Bonavista's US denominated senior unsecured notes as a result of the weakening CDN dollar relative to the US dollar.

Net financing costs increased 7% to $42.1 million for the three months ended December 31, 2015, from net financing costs of $39.5 million in the same period in 2014. This change is largely attributable to lower unrealized foreign exchange losses associated with the revaluation of Bonavista's US dollar denominated senior unsecured notes, partially offset by higher unrealized gains on the fair value of foreign exchange financial instrument contracts. The increase in net financing costs was also impacted by higher interest costs associated with the translation of US dollar interest associated with Bonavista's US denominated senior unsecured notes as a result of the weakening CDN dollar relative to the US dollar. Similarly, for the three months ended December 31, 2015, net financing costs on a per boe basis increased 15% to $5.73 per boe compared to $5.00 per boe recognized in the same period in 2014, for similar reasons as stated above. Net financing costs, excluding non-cash amounts, increased 16% to $12.9 million for the three months ended December 31, 2015, compared to $11.1 million for the three months ended December 31, 2014. The increase in net financing costs, excluding non-cash amounts, was due to the translation of US dollar interest on Bonavista's US denominated senior unsecured notes discussed above. Net financing costs, excluding non-cash amounts, on a per boe basis increased 25% to $1.75 per boe for the three months ended December 31, 2015 compared to $1.40 per boe in the same period in 2014.

Deferred income tax (recovery) - For the year ended December 31, 2015, the deferred income tax recovery was $204.1 million compared to a provision of $34.3 million recognized in the same period in 2014. The deferred income tax recovery for the three months ended December 31, 2015 was $155.3 million compared to a deferred income tax recovery of $6.1 million recognized in the same period in 2014. The deferred income tax recovery for the three months and year ended December 31, 2015 was lower than the recovery calculated using the statutory rate as a result of the income tax treatment of net foreign currency translation gains and losses on Bonavista's US denominated senior unsecured notes and financial instrument contracts, income tax treatment of non-deductible share-based compensation expense and the impact of the increase in the Alberta corporate income tax rate from 10% to 12% effective July 1,2015. Bonavista made no cash payments or tax installments for the three months and year ended December 31, 2015 or for the comparative period in 2014.

Funds from operations, net income (loss) and comprehensive income (loss) - For the year ended December 31, 2015, funds from operations decreased 31% to $385.4 million ($1.77 per share, basic) from $561.1 million ($2.69 per share, basic) in the same period in 2014. While production volumes increased 3%, funds from operations was impacted by a 28% decrease in production revenues, including the impact of financial instrument commodity contracts, partially offset by the impact of lower royalties and operating expenses. For the three months ended December 31, 2015, Bonavista experienced a 29% decrease in funds from operations to $95.8 million ($0.44 per share, basic) from $135.8 million ($0.63 per share, basic) in the same period in 2014. The decrease in funds from operations resulted from a 28% decrease in production revenues, including the impact of financial instrument commodity contracts, when compared to the same period in 2014.

Bonavista recorded a net loss and comprehensive loss for the year ended December 31, 2015 of $751.5 million ($3.45 per share, basic) compared to net income and comprehensive income of $4.8 million ($0.02 per share, basic) for the prior period year. Net loss and comprehensive loss for the year ended December 31, 2015 increased when compared to the year ended December 31, 2014 as a result of a 31% decrease in funds from operations and the $812.0 million in impairment charges resulting from the continued decline in the commodity price forecasts at January 1, 2016 when compared to January 1, 2015. Net loss and comprehensive loss for the three months ended December 31, 2015 increased to $454.6 million ($2.09 per share, basic) when compared to a net loss and comprehensive loss of $61.0 million ($0.28 per share, basic) in the same period in 2014. Net loss and comprehensive loss for the three months ended December 31, 2015 increased for similar reasons as stated above.

The following table is a reconciliation of an additional IFRS measure, funds from operations, to its nearest measure prescribed by IFRS:

	Three months ended December 31		Years ended December 31	
Calculation of Funds From Operations:	**2015**	2014	**2015**	2014
($ thousands)				
Cash flow from operating activities	**126,735**	139,349	**406,290**	593,824
Interest expense	**(12,860)**	(11,060)	**(49,716)**	(43,921)
Decommissioning expenditures	**3,281**	9,944	**18,925**	32,026
Changes in non-cash working capital	**(21,364)**	(2,388)	**9,852**	(20,824)
Funds from operations	**95,792**	135,845	**385,351**	561,105

Capital expenditures - Consistent with Bonavista's asset concentration strategy, capital expenditures for the year ended December 31, 2015 were predominately focused on further development of the Glauconite and Falher plays in the West Central core area and the Wilrich play in the Deep Basin core area. For the year ended December 31, 2015, investment in exploration and development activities totaled $313.9 million, a 51% decrease compared to $639.6 million in the same period in 2014. Similarly, for the three months ended December 31, 2015, Bonavista's investment in exploration and development activities was $56.1 million, a 65% decrease from $162.2 million in the comparative 2014 period. The decrease in exploration and development expenditures in 2015 resulted from prudent capital spending driven by the prolonged weakness in global commodity prices which continued to decline throughout 2015.

For the year ended December 31, 2015, non-core dispositions totaled $100.1 million, resulting in a gain on sale of property, plant and equipment of $19.9 million and $14.5 million gain on sale of exploration and evaluation assets. During the comparative 2014 period, proceeds of $293.4 million were received largely for non-core oil weighted properties resulting in a gain on sale of property, plant and equipment of $61.8 million and a $5.9 million gain on the sale of exploration and evaluation assets. During the year ended December 31, 2015, Bonavista acquired, through asset exchanges and property acquisitions, certain properties and petroleum and natural gas rights within its core areas for $69.6 million compared to $186.6 million in 2014 to acquire assets predominantly located in Ansell within the Deep Basin core area. Head office capital expenditures for the year ended 2015 were $1.2 million compared to $3.0 million in the same period of 2014.

During the three months ended December 31, 2015, Bonavista successfully disposed of certain non-core assets through asset exchanges and a property disposition for $7.1 million, resulting in a loss on the sale of property, plant and equipment of $0.6 million and a $8.3 million loss on sale of exploration and evaluation assets. During the comparative period in 2014, dispositions totaled $99.4 million, consisting mainly of non-core oil weighted properties. Head office capital expenditures for the three months ended December 31, 2015 were $0.1 million compared to $0.4 million in the same period in 2014.

The following table outlines capital expenditures by category for the three months and years ended December 31:

	Three months ended December 31		Years ended December 31	
	2015	2014	**2015**	2014
($ thousands)				
Land acquisitions	**1,507**	14,816	**7,823**	29,391
Geological and geophysical	**1,233**	1,576	**9,759**	14,837
Drilling and completion	**40,413**	115,642	**230,724**	442,237
Production equipment and facilities	**12,931**	30,121	**65,599**	153,095
Exploration and development expenditures	**56,084**	162,155	**313,905**	639,560
Business and other acquisitions	**1,572**	11,580	**69,576**	186,608
Dispositions	**(7,112)**	(99,448)	**(100,128)**	(293,385)
Head office expenditures	**74**	449	**1,203**	3,018
Net capital expenditures	**50,618**	74,736	**284,556**	535,801

Liquidity and capital resources - As at December 31, 2015, net debt, was $1.3 billion with a debt to fourth quarter 2015 annualized funds from operations ratio of 3.4:1.

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, senior unsecured notes and adjusted working capital, divided by funds from operations for the most recent calendar quarter, annualized (multiplied by four). This ratio may increase at certain times as a result of acquisitions or low commodity prices.

To facilitate the management of this ratio, Bonavista prepares annual funds from operations and capital expenditure budgets, which are updated as necessary, and are reviewed and periodically approved by Bonavista’s Board of Directors. The Corporation manages its capital structure and makes adjustments by continually monitoring its business conditions, including: the current economic conditions; the risk characteristics of Bonavista's 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 differentials, royalties, operating costs and transportation costs.

To maintain or adjust the capital structure, Bonavista 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 Corporation's lenders; the availability of other sources of debt with different characteristics than the existing bank debt; the sale of assets; the monetization of financial instrument contracts; limiting the size of the capital expenditure program; issuance of new equity if available on favourable terms; and its level of dividends payable to its shareholders. Bonavista shareholders' capital is not subject to external restrictions, however, the Corporation's bank credit facility and senior unsecured notes do contain financial covenants that are outlined in note 11 of the consolidated financial statements.

The following table represents Bonavista's ratio of net debt to funds from operations as follows:

Net Debt to Funds from Operations	**Year ended December 31, 2015**	Year ended December 31, 2014
($ thousands)		
Long Term Debt	**1,231,031**	989,671
Adjusted working capital deficiency(1)	**79,632**	165,751
Total net debt(1)	**1,310,663**	1,155,422
Funds from operations fourth quarter annualized	**383,168**	543,380
Total net debt to funds from operations	**3.4:1**	2.1:1
Funds from operations for the year ended December 31, 2015	**385,351**	561,105
Total net debt to funds from operations	**3.4:1**	2.1:1

(1) Additional IFRS measure.

As at December 31, 2015, Bonavista's bank debt outstanding was $272.1 million bearing a weighted average interest rate of 3.8% in comparison as at December 31, 2014 Bonavista's bank debt outstanding was $154.4 million bearing a weighted average interest rate of 3.2%. On September 10, 2015, Bonavista amended and renewed its existing bank credit facility of $600 million provided by a syndicate of 11 domestic and international banks to a maturity date of September 10, 2019. The amendments made to the bank credit facility pertain to the applicable banks' prime rate and stamping fee for advances made under the facility. As at December 31, 2015, Bonavista had approximately $325.8 million of unused borrowing capacity on its $600 million bank credit facility.

Bonavista's senior unsecured notes totaled $1.0 billion as at December 31, 2015 which consists of US$705.0 million (CDN$975.7 million) and CDN$20.0 million. Bonavista's senior unsecured notes bear fixed interest rates, with a weighted average rate of 4.1% for the years ended December 31, 2015 and 2014. The senior unsecured notes have a five year weighted average life with the majority of the debt repayments due in 2019 and thereafter.

As at December 31, 2015, Bonavista was in compliance with all covenants under its bank credit facility, senior unsecured notes issued under the master shelf agreement and senior unsecured notes not subject to the master shelf agreement. Total debt to earnings before interest; taxes; depletion, depreciation, amortization and impairment (EBIDTA) and total senior debt to EBIDTA was 2.8 times compared to the covenant of 3.5 times and total debt to capitalization was 0.45 times compared to the covenant of 0.5 times.

While operational success continued in 2015, the continued decline in commodity prices continues to present a challenging environment for the North American energy sector, Bonavista remains committed to preserving financial flexibility and the prudent use of debt. Bonavista remains focused on creating value for its shareholders by consistently aligning the capital program and dividends with funds from operations. For 2016, Bonavista plans to invest between $145 million and $190 million on its capital program within its core areas, to drill between 30.0 net and 50.0 net wells. With an approximate payout ratio of 70% in 2016 using our base budget of $145 million in capital spending along with the revised dividend of $0.01 per share per quarter allows us to apply the remaining funds from operations, of approximately $70 million, to our net debt.

Shareholders' equity - As at December 31, 2015, Bonavista had 218.6 million equivalent common shares outstanding. This includes 3.3 million exchangeable shares, which are exchangeable into 4.6 million common shares. The exchange ratio in effect at December 31, 2015 for exchangeable shares was 1.39313:1. As at February 25, 2016, Bonavista had 218.6 million equivalent common shares outstanding. This includes 3.3 million exchangeable shares, which are exchangeable into 4.6 million common shares. The exchange ratio in effect at February 25, 2016 for exchangeable shares was 1.40915:1. In addition, Bonavista has 0.3 million stock option and common share incentive rights outstanding as at February 25, 2016, with an average exercise price of $17.89 per common share and 2.9 million incentive and restricted share awards and 2.2 million performance incentive awards outstanding.

Dividends - For the year ended December 31, 2015, Bonavista declared dividends of $76.8 million ($0.37 per share) compared to $164.8 million ($0.84 per share) in the same period in 2014. For the three months ended December 31, 2015, Bonavista declared dividends of $11.7 million ($0.055 per share) compared to $42.8 million ($0.21 per share) for the same period in 2014.

Dividends are approved 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. Effective April 1, 2016, our Board of Directors has approved a 67% reduction in the dividend to $0.01 per share per quarter. Bonavista announces its dividend policy on a quarterly basis and confirms its dividend payment on a quarterly basis.

Annual financial information - The following table highlights selected annual financial information for each of the three years ended December 31, 2015, 2014 and 2013.

Years ended December 31	**2015**	2014	2013
($ thousands, except per share amounts)			
Consolidated Statement of Income and Comprehensive Income Information			
Production revenues, net of royalties	**545,798**	970,757	839,823
Funds from operations	**385,351**	561,105	477,578
per share - basic	**1.77**	2.69	2.42
per share - diluted	**1.75**	2.66	2.40
Net income	**(751,545)**	4,847	49,505
per share - basic	**(3.45)**	0.02	0.25
per share - diluted	**(3.45)**	0.02	0.25
Consolidated Statement of Financial Position Information			
Net capital expenditures	**284,556**	535,801	470,542
Total assets	**3,523,716**	4,429,402	4,235,626
Working capital deficiency[(1)]	**(16,230)**	(27,173)	(109,587)
Long-term debt	**1,231,031**	989,671	1,046,177
Shareholders' equity	**1,548,266**	2,357,706	2,270,015
Dividends declared	**76,762**	164,750	152,968

(1) Excluding decommissioning liabilities.

Quarterly financial information - The following table highlights Bonavista's performance for the eight quarterly periods ending on March 31, 2014 to December 31, 2015:

	2015				**2014**			
	December 31	September 30	June 30	March 31	December 31	September 30	June 30	March 31
($ thousands, except per share amounts)								
Production revenues	137,260	148,342	150,110	164,287	244,612	259,678	287,529	315,033
Net income (loss)	(454,616)	(216,187)	(1,882)	(78,860)	(60,978)	24,186	86,576	(44,937)
Basic	(2.09)	(0.99)	(0.01)	(0.36)	(0.28)	0.11	0.43	(0.22)
Diluted	(2.09)	(0.99)	(0.01)	(0.36)	(0.28)	0.11	0.42	(0.22)

Production revenues over the past eight quarters have fluctuated largely due to the volatility of commodity prices and changes in production volumes. Net income (loss) in the past eight quarters has fluctuated from a net loss of $454.6 million in the fourth quarter of 2015 to net income of $86.6 million in the second quarter of 2014. These fluctuations are primarily influenced by production volumes, commodity prices, realized and unrealized gains and losses on financial instrument commodity contracts, unrealized gains and losses on the revaluation of Bonavista's US dollar denominated senior unsecured notes and impairment charges.

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 designed, or caused to be designed under their supervision, disclosure controls and procedures, as defined by National Instrument 52-109 Certification, to provide reasonable assurance that (i) material information relating to the Corporation is made known to the Corporation's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are prepared; and (ii) information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. All control systems by their nature have inherent limitations and, therefore, the Corporation's disclosure controls and procedures are believed to provide reasonable, but not absolute, assurance that the objectives of the control system are met.

Internal control over financial reporting - The Corporation's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting, as defined by National Instrument 51-109. Internal controls 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. There were no changes made to Bonavista's internal controls over financial reporting during the period beginning on January 1, 2015 and ending on December 31, 2015 that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting. In May 2013, the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") issued an updated Internal Control-Integrated Framework *("2013 Framework")* replacing *the Internal Control - Integrated Framework (1992)*. Bonavista has adopted the *2013 Framework*.

Future accounting policies - Below is a brief description of new IFRS standards and amendments that are not yet effective and have not been applied in the preparation of these financial statements. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material impact on the Corporation's financial statements.

- On December 18, 2014, the IASB issued amendments to IAS 1, "Presentation of Financial Statements". These amendments will not require significant changes to the Corporation's current practices but are aimed to facilitate improved financial statement disclosures. The amendments are effective for annual periods beginning on or after January 1, 2016 with early adoption permitted. The Corporation intends to adopt these amendments in its financial statements for the annual period beginning on January 1, 2016. The Corporation does not expect these amendments to have a material impact on its financial statements.
- On May 28, 2014, the IASB issued IFRS 15, "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The new standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Corporation intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of the adoption of the standard has not yet been determined.
- On July 24, 2014, the IASB issued the complete IFRS 9, "Financial Instruments" to replace IAS 39, "Financial Instruments: Recognition and Measurement". IFRS 9, as amended, includes a principle-based approach for the classification and measurement of financial assets, a single 'expected credit loss' impairment model and a new hedge accounting standard which aligns hedge accounting more closely with risk management. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Corporation intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018.The extent of the impact of the adoption of the standard has not yet been determined.
- On January 13, 2016, the IASB issued IFRS 16, "Leases", which replaces IAS 17 "Leases". The new standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than twelve months. The new standard is effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the initial adoption date of January 1, 2018. The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The extent of the impact of the adoption of the standard has not yet been determined.

Critical accounting estimates - The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"). A summary of the significant accounting policies are presented in note 2 of the Notes to the Consolidated Financial Statements. The timely preparation of Bonavista's financial statements requires management to make certain judgments, estimates and assumptions. These estimates and judgments are subject to changes and actual results could differ from those estimated. Significant judgments and estimates made by management in the preparation of the financial statements are outlined below.

- *Determination of a Cash Generating Unit ("CGU")* - The determination of Bonavista's CGUs is subject to management's judgment. In determining Bonavista's CGUs, management assessed what constituted independent cash flows and how to aggregate the respective assets. The asset composition of each CGU can directly impact the assessment of the recoverability of those assets included within each CGU. In 2015, there were no changes to the composition of Bonavista's CGU's as compared to 2014.
- *Impairment testing* - Bonavista assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, Bonavista performs an impairment test on the CGU, which is the lowest level at which there are identifiable cash flows. The carrying amount of each CGU is compared to its recoverable amount which is defined as the greater of its fair value less cost to sell and value in use and is subject to management estimates. Key estimates used in the determination of these cash flows include: quantities of reserves and future production; future commodity pricing; development costs; operating costs; royalty obligations; and discount rates. Any changes in these estimates may have an impact on the recoverable amount of the CGU.
- *Proved plus probable oil and natural gas reserves* - Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to interpretation and uncertainty. Bonavista expects that over time its reserve estimates will be revised either upward or downward depending upon the factors as stated above. These reserve estimates can have a significant impact on net income, as it is a key component in the calculation of depletion, depreciation and amortization, and also for the determination of potential asset impairments.
- *Depreciation, depletion and amortization* - Property, plant and equipment is measured at cost less accumulated depreciation, depletion and amortization. Bonavista's oil and natural gas properties are depleted using the unit-of-production method over proved plus probable reserves for each CGU. The unit-of-production method takes into account estimates of capital expenditures incurred to date along with future development capital required to develop both proved plus probable reserves.
- *Decommissioning liability* - The provision for decommissioning liabilities is based on management's estimates of costs and planned remediation projects. Actual costs may differ from those estimated due to changes in governing environment laws and regulations, technological changes, and market conditions.
- *Financial Instrument contracts* - The estimated fair value of financial instrument commodity contracts are subject to changes in forward looking commodity prices, interest rate curves, volatility curves and counterparty non-performance risk. The estimated fair values of the Corporation's financial instrument contracts are subject to changes in foreign exchange rates.

BONAVISTA ENERGY CORPORATION

MANAGEMENT'S REPORT

The Consolidated Financial Statements of Bonavista Energy Corporation and related financial information were prepared by, and are the responsibility of Management. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards. The Consolidated Financial Statements and related financial information reflect amounts which must of necessity be based upon informed estimates and judgments of Management with appropriate consideration to materiality. The Corporation has developed and maintains systems of controls, policies and procedures in order to provide reasonable assurance that assets are properly safeguarded, and that the financial records and systems are appropriately designed and maintained, and provide relevant, timely and reliable financial information to Management.

The Consolidated Financial Statements have been audited by KPMG LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders.

The Board of Directors has established an Audit Committee. The Audit Committee reviews with Management and the external auditors any significant financial reporting issues, the Consolidated Financial Statements, and any other matters of relevance to the parties. The Audit Committee meets quarterly to review and approve the consolidated interim financial statements prior to their release, as well as annually to review the Corporation's annual Consolidated Financial Statements and Management's Discussion and Analysis and to recommend their approval to the Board of Directors.

The external auditors have unrestricted access to the Corporation, the Audit Committee and the Board of Directors.

Jason E. Skehar President and Chief Executive Officer	Dean M. Kobelka Vice President Finance and Chief Financial Officer

February 25, 2016
Calgary, Alberta

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Bonavista Energy Corporation

We have audited the accompanying consolidated financial statements of Bonavista Energy Corporation, which comprise the consolidated statements of financial position as at December 31, 2015 and December 31, 2014, the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Bonavista Energy Corporation as at December 31, 2015 and December 31, 2014, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants

February 25, 2016

Calgary, Canada

BONAVISTA ENERGY CORPORATION

Consolidated Statements of Financial Position

As at December 31	**Note**	**2015**	2014
($ thousands)			
Assets			
Current assets			
Accounts receivable		**70,278**	102,840
Prepaid expenses		**8,333**	9,525
Marketable securities		**102**	814
Other assets		**14,104**	19,358
Financial instrument commodity contracts	(4)	**66,213**	140,271
Financial instrument contracts	(4)	**2,013**	—
		161,043	272,808
Financial instrument commodity contracts	(4)	**19,390**	17,680
Financial instrument contracts	(4)	**68,754**	16,025
Property, plant and equipment	(8)	**3,064,335**	3,933,396
Exploration and evaluation assets	(9)	**210,194**	189,493
Total assets		**3,523,716**	4,429,402
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities		**137,722**	234,025
Current portion of long-term debt	(11)	**34,600**	50,000
Decommissioning liabilities	(12)	**18,559**	15,185
Dividends payable		**2,140**	14,263
Financial instrument commodity contracts	(4)	**2,811**	1,693
		195,832	315,166
Financial instrument commodity contracts	(4)	**2,289**	2,385
Long-term debt	(11)	**1,231,031**	989,671
Other long-term liabilities		**10,742**	12,412
Decommissioning liabilities	(12)	**470,342**	482,797
Deferred income taxes	(13)	**65,214**	269,265
		1,975,450	2,071,696
Shareholders' equity	(10)		
Shareholders' capital		**2,716,011**	2,514,006
Exchangeable shares		**94,550**	272,900
Contributed surplus		**52,825**	57,613
Deficit		**(1,315,120)**	(486,813)
		1,548,266	2,357,706
Commitments	(14)		
Total liabilities and shareholders' equity		**3,523,716**	4,429,402

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors of Bonavista Energy Corporation

Ian S. Brown, Director

Michael M. Kanovsky, Director

BONAVISTA ENERGY CORPORATION

Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

For the years ended December 31	Note	2015	2014
($ thousands, except per share amounts)			
Revenues			
Production		**599,999**	1,106,852
Royalties		**(54,201)**	(136,095)
		545,798	970,757
Realized gains (losses) on financial instrument commodity contracts	(4)	**149,153**	(65,232)
Unrealized gains (losses) on financial instrument commodity contracts	(4)	**(73,370)**	188,803
		621,581	1,094,328
Expenses			
Operating		**190,889**	232,474
Transportation		**36,500**	36,013
General and administrative		**32,495**	32,012
Share-based compensation	(10)	**17,157**	20,449
Gain on disposition of property, plant and equipment	(8)	**(19,946)**	(61,780)
Loss (gain) on disposition of exploration and evaluation assets	(8)	**(14,534)**	5,903
Depletion, depreciation, amortization and impairment	(8)	**1,168,016**	670,510
		1,410,577	935,581
Income from operating activities		**(788,996)**	158,747
Finance costs	(6)	**221,342**	127,579
Finance income	(6)	**(54,742)**	(8,002)
Net finance costs		**166,600**	119,577
Income (loss) before taxes		**(955,596)**	39,170
Deferred income tax (recovery)	(13)	**(204,051)**	34,323
Net income (loss) and comprehensive income (loss)		**(751,545)**	4,847
Net income (loss) and comprehensive income (loss) per share			
Basic		**(3.45)**	0.02
Diluted		**(3.45)**	0.02

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY CORPORATION
Consolidated Statements of Changes in Equity

For the years ended December 31	Shareholders' Capital	Exchangeable Shares	Contributed Surplus	Deficit	Total Shareholders' Equity
($ thousands)					
Balance as at December 31, 2013	2,228,210	307,468	61,247	(326,910)	2,270,015
Net income and comprehensive income	—	—	—	4,847	4,847
Issuance of equity	200,860	—	—	—	200,860
Issue costs, net of future tax benefit	(6,280)	—	—	—	(6,280)
Issued for cash on exercise of stock options and common share incentive rights	4,154	—	—	—	4,154
Exercise of stock options and common share incentive rights	4,550	—	(4,550)	—	—
Conversion of incentive and restricted share awards	21,721	—	(21,721)	—	—
Tax effect on conversion of incentive awards	148	—	—	—	148
Share-based compensation expense	—	—	20,449	—	20,449
Share-based compensation capitalized	—	—	2,188	—	2,188
Issued pursuant to the dividend reinvestment and stock dividend plans	26,075	—	—	—	26,075
Exchangeable shares exchanged for common shares	34,568	(34,568)	—	—	—
Dividends declared	—	—	—	(164,750)	(164,750)
Balance as at December 31, 2014	2,514,006	272,900	57,613	(486,813)	2,357,706
Net loss and comprehensive loss	**—**	**—**	**—**	**(751,545)**	**(751,545)**
Conversion of incentive and restricted share awards	**23,655**	**—**	**(23,655)**	**—**	**—**
Share-based compensation expense	**—**	**—**	**17,157**	**—**	**17,157**
Share-based compensation capitalized	**—**	**—**	**1,710**	**—**	**1,710**
Exchangeable shares exchanged for common shares	**178,350**	**(178,350)**	**—**	**—**	**—**
Dividends declared	**—**	**—**	**—**	**(76,762)**	**(76,762)**
Balance as at December 31, 2015	**2,716,011**	**94,550**	**52,825**	**(1,315,120)**	**1,548,266**

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY CORPORATION
Consolidated Statements of Cash Flows

For the years ended December 31	Note	2015	2014
($ thousands)			
Cash provided by (used for):			
Operating Activities			
Net income (loss) and comprehensive income (loss)		**(751,545)**	4,847
Adjustments for:			
Depletion, depreciation, amortization and impairment		**1,168,016**	670,510
Share-based compensation		**17,157**	20,449
Unrealized losses (gains) on financial instrument commodity contracts		**73,370**	(188,803)
Gain on disposition of property, plant and equipment		**(19,946)**	(61,780)
Loss (gain) on disposition of exploration and evaluation assets		**(14,534)**	5,903
Net finance costs		**166,600**	119,577
Deferred income tax (recovery)		**(204,051)**	34,323
Decommissioning expenditures		**(18,925)**	(32,026)
Changes in non-cash working capital items	(7)	**(9,852)**	20,824
		406,290	593,824
Financing Activities			
Issuance of equity, net of issue costs		**—**	192,476
Proceeds on exercise of stock options and common share incentive rights		**—**	4,154
Dividends paid		**(88,885)**	(137,499)
Interest paid		**(48,946)**	(43,550)
Proceeds from long-term debt		**66,578**	—
Repayment of long-term debt		**—**	(75,827)
		(71,253)	(60,246)
Investing Activities			
Business acquisition		**—**	(141,062)
Exploration and development		**(313,905)**	(639,560)
Property acquisitions		**(69,576)**	(45,546)
Property dispositions		**100,128**	289,385
Office equipment		**(1,203)**	(3,018)
Changes in non-cash working capital items	(7)	**(50,481)**	6,223
		(335,037)	(533,578)
Change in cash and cash equivalents		**—**	—
Cash and cash equivalents, beginning of year		**—**	—
Cash and cash equivalents, end of year		**—**	—

See accompanying notes to the consolidated financial statements.

Structure of the Corporation and Basis of Presentation

The principal undertakings of Bonavista Energy Corporation ("Bonavista" or the "Corporation") are to carry on the business of acquiring, developing and holding interests in oil and natural gas properties and assets in Western Canada.

Bonavista's principal place of business is located at 1500, 525 - 8th Avenue SW, Calgary, Alberta, Canada T2P 1G1.

The consolidated financial statements of the Corporation as at and for the year ended December 31, 2015, are available through our filings on SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

1. Basis of Presentation

Statement of compliance

The consolidated financial statements (the "financial statements") have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). A summary of Bonavista's significant accounting policies under IFRS are presented in note 2.

These financial statements were authorized for issue by the Corporation's Board of Directors on February 25, 2016.

Basis of measurement

These financial statements have been prepared on the historical cost basis except for derivative financial instruments, which are measured at fair value.

Functional and presentation currency

These financial statements are presented in Canadian (CDN) dollars, which is the Corporation's functional currency.

Use of management's judgments and estimates

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the consolidated financial statements and the reported amounts of revenue and expenses during the period. Estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the consolidated financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as Bonavista's operating environment changes.

Estimates and underlying assumptions are reviewed on an ongoing basis by management. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The key sources of estimation uncertainty to the carrying amounts of assets and liabilities are discussed below:

i. Determination of a Cash Generating Unit ("CGU")

The determination of Bonavista's CGUs is subject to management's judgment. In determining Bonavista's CGUs, management assessed what constituted independent cash flows and how to aggregate the respective assets. The asset composition of each CGU can directly impact the assessment of the recoverability of those assets included within each CGU. In 2015, there were no changes to the composition of Bonavista's CGUs as compared to 2014.

ii. Impairment testing

Bonavista assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, Bonavista performs an impairment test on the CGU, which is the lowest level at which there are identifiable cash flows. The carrying amount of each CGU is compared to its recoverable amount which is defined as the greater of its fair value less cost to sell and value in use and is subject to management estimates.

As at December 31, 2015, Bonavista evaluated each of its CGUs for indicators of impairment. In performing this evaluation, management used the net present values for each CGU. Key estimates used in the determination of these cash flows include: quantities of reserves and future production; future commodity pricing; development costs; operating costs; royalty obligations; and discount rates. Any changes in these estimates may have an impact on the recoverable amount of the CGU.

iii. Proved plus probable oil and natural gas reserves

Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to interpretation and uncertainty. Bonavista expects that over time its reserve estimates will be revised either upward or downward depending upon the factors as stated above. These reserve estimates can have a significant impact on net income, as it is a key component in the calculation of depletion, depreciation and amortization, and also for the determination of potential asset impairments.

iv. Depreciation, depletion and amortization

Property, plant and equipment is measured at cost less accumulated depreciation, depletion and amortization. Bonavista's oil and natural gas properties are depleted using the unit-of-production method over proved plus probable reserves for each CGU. The unit-of-production method takes into account estimates of capital expenditures incurred to date along with future development capital required to develop both proved plus probable reserves.

v. Decommissioning liability

The provision for decommissioning liabilities is based on management's estimates of costs and planned remediation projects. Actual costs may differ from those estimated due to changes in governing environment laws and regulations, technological changes, and market conditions.

vi. Financial Instrument contracts

The estimated fair value of financial instrument commodity contracts are subject to changes in forward looking commodity prices, interest rate curves, volatility curves and counterparty non-performance risk. The estimated fair values of the Corporation's financial instrument contracts are subject to changes in foreign exchange rates.

2. Significant accounting policies

Basis of consolidation

The consolidated financial statements comprise the financial statements of the Corporation and its subsidiaries as at December 31, 2015. Subsidiaries are consolidated from the date of acquisition, being the date on which Bonavista obtains control, and continues to be consolidated until the date that control ceases. Control exists when Bonavista has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. All intercompany balances and transactions, and any unrealized income and expenses, arising from intercompany transactions are eliminated in full.

Many of Bonavista's oil and natural gas activities involve jointly controlled assets. The consolidated financial statements include Bonavista's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

Foreign currency

Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are translated to the functional currency at the exchange rate at the date that the fair value was determined. Foreign currency differences arising on translation are recognized in profit or loss.

Financial instruments

i. Non-derivative financial assets

Bonavista initially recognizes loans, receivables and deposits on the date that they are originated. All other financial assets (including assets designated at fair value through profit or loss) are recognized initially on the date at which Bonavista becomes a party to the contractual provisions of the instrument.

The Corporation derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. Any interest in transferred financial assets that is created or retained by Bonavista is recognized as a separate asset or liability.

Financial assets and liabilities are offset and the net amount is presented in the statement of consolidated financial position when, and only when, Bonavista has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

Bonavista classifies non-derivative financial assets into the following categories: financial assets at fair value through profit or loss, held-to-maturity financial assets, loans and receivables and available-for-sale financial assets.

Financial assets at fair value through profit or loss

A financial asset is classified at fair value through profit or loss if it is classified as held for trading or is designated as such upon initial recognition. Financial assets are designated at fair value through profit or loss if Bonavista manages such investments and makes purchase and sale decisions based on their fair value in accordance with Bonavista's documented risk management or investment strategy. Attributable transaction costs are recognized in profit or loss as incurred.

Financial assets at fair value through profit or loss are measured at fair value and changes therein are recognized in the consolidated statement of income.

Loans and receivables

Loans and receivables are financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, loans and receivables are measured at amortized cost using the effective interest method, less any impairment losses.

Loans and receivables comprise of cash and cash equivalents, and trade and other receivables.

Cash and cash equivalents

Cash and cash equivalents comprise cash balances and call deposits with original maturities of three months or less.

ii. Non-derivative financial liabilities

Bonavista initially recognizes debt securities issued and subordinated liabilities on the date that they are originated. All other financial liabilities (including liabilities designated at fair value through profit or loss) are recognized initially on the trade date at which Bonavista becomes a party to the contractual provisions of the instrument.

Bonavista derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

Bonavista classifies non-derivative financial liabilities into the other financial liabilities category. Such financial liabilities are recognized initially at fair value plus any directly attributable transaction costs. Subsequent to initial recognition, these financial liabilities are measured at amortized cost using the effective interest method.

Other financial liabilities comprise loans and borrowings, bank overdrafts, and trade and other payables.

Bank overdrafts that are repayable on demand and form an integral part of Bonavista's cash management are included as a component of cash and cash equivalents for the purpose of the consolidated statement of cash flows.

iii. Derivative financial instruments

Bonavista has entered into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices and foreign exchange rates. These instruments are not used for trading or speculative purposes. Bonavista has not designated its financial derivative contracts as effective accounting hedges, and thus not applied hedge accounting, even though the Corporation considers all commodity contracts and foreign exchange contracts to be economic hedges. Derivatives are recognized initially at fair value and any attributable transaction costs are recognized in profit or loss when incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein are recognized immediately in profit or loss.

Bonavista has accounted for its forward 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. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the consolidated statement of financial position. Settlements on these physical sales contracts are recognized in oil and natural gas revenues.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in the consolidated statement of income.

Financial assets designated at fair value through profit or loss are comprised of interest rate swaps and forward exchange contracts.

iv. Shareholders’ capital and Exchangeable shares

Common shares and exchangeable shares are classified as equity. Incremental costs directly attributable to the issue of common shares and share options are recognized as a deduction from equity, net of any tax effects.

Exploration and evaluation assets and property, plant and equipment

Recognition and measurement

Pre-licence costs are recognized in the consolidated statement of income as incurred.

Exploration and evaluation expenditures

Exploration and evaluation (“E&E”) costs, including the costs of acquiring licences and directly attributable general and administrative costs are initially capitalized as either tangible or intangible E&E assets according to the nature of the assets acquired. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability. E&E assets are assessed for impairment if: (a) sufficient data exists to determine technical feasibility and commercial viability; and (b) facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when total proved plus probable reserves are determined to exist. Annually, a review of each exploration licence or field is carried out, to ascertain whether proved plus probable reserves have been discovered. Upon determination of total proved plus probable reserves, intangible E&E assets attributable to those reserves are transferred from E&E assets to a separate category within tangible assets referred to as oil and natural gas properties.

Gains and losses on dispositions of exploration and evaluation assets, are determined by comparing the proceeds from disposal with the carrying amount of exploration and evaluation assets and are recognized on a net basis within “gains (losses) on disposition of exploration and evaluation assets” in the consolidated statement of income.

Development and production costs

Items of property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. Development and production assets are grouped into cash generating units for impairment testing.

Gains and losses on dispositions of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized on a net basis within “gains (losses) on disposition of property, plant and equipment” in the consolidated statement of income.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved or proved plus probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in the consolidated statement of income as incurred.

Depletion, depreciation and amortization

The net carrying amount of development or production assets is depleted using the unit-of-production method by reference to the ratio of production in the year to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Proved plus probable reserves are estimated using independent reserve engineer reports and represent the estimated quantities of oil, natural gas and natural gas liquids, which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50% statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved plus probable and a 50% statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proved plus probable reserves are 90% and 10%, respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;
- a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered total proved plus probable if producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proved includes: (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both; and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved plus probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

The estimated useful lives for certain production assets for the current and comparative years are as follows:

Facilities	15 years
Oil and natural gas properties	Based on CGU Reserve Life

For other assets, depreciation is recognized in profit or loss on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment. Leased assets are depreciated over the shorter of the lease term and their useful lives unless it is reasonably certain that Bonavista will obtain ownership by the end of the lease term.

The estimated useful lives for other assets for the current and comparative years are as follows:

Office equipment	5 years
Fixtures and fittings	5 years
Leaseholds	9.5 years

Depreciation methods, useful lives and residual values are reviewed at each reporting date.

Goodwill and Exploration and evaluation assets

Goodwill

Goodwill arises on the acquisition of businesses, subsidiaries, associates and joint ventures. Goodwill is measured at cost less accumulated impairment losses. Goodwill is evaluated for impairment on an annual basis, or more frequently if potential indicators of impairment exist.

Exploration and evaluation assets

Other intangible assets that are acquired by Bonavista, which have finite useful lives, are measured at cost less accumulated amortization and accumulated impairment losses.

Subsequent expenditure is capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of other intangible assets, other than goodwill, from the date they were available for use.

Impairment

Non-derivative financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in the consolidated statement of income.

An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in the consolidated statement of income.

Non-financial assets

The carrying amounts of Bonavista's non-financial assets, other than E&E assets and deferred income tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. An impairment test is completed each year for goodwill and other intangible assets that have indefinite lives or that are not yet available for use. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as oil and natural gas interests, and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets, the CGU. The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs to sell.

In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. Value in use is generally computed by reference to the present value of the future cash flows expected to be derived from production of proved plus probable reserves.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to the CGUs that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the unit (group of units) on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, impairment losses recognized in prior years are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation or amortization, if no impairment loss had been recognized.

Employee benefits

Share-based compensation

Long-term incentives are granted to officers, directors, employees and certain consultants in accordance with Bonavista's stock option, incentive award and restricted share award plans.

The fair value of stock options is assessed on the grant date using the Black-Scholes option pricing model. The fair value is subsequently recognized as compensation expense over the vesting period with a corresponding increase in contributed surplus. Upon exercise of the options, consideration paid by the stock option holders and the value in contributed surplus pertaining to the exercised options is recorded as shareholders' capital.

The fair value of incentive awards and restricted share awards is assessed on the grant date factoring in the weighted average trading price of the five days preceding the grant date and forecasted dividends. This fair value is recognized as compensation expense over the vesting period with a corresponding increase in contributed surplus. Upon the conversion of the restricted share awards or the settlement of the incentive awards by common shares, on the predetermined vesting dates, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital.

The fair value of performance incentive awards is assessed on grant date by using the closing price of common shares and multiplied by the estimated performance multiplier. The performance multiplier can range from 0 to 2 and is dependent on the performance of the Corporation at the end of the vesting period relative to corporate performance measures determined at the discretion of Bonavista's Board of Directors. The fair value is recognized as compensation expense over the vesting period with a corresponding increase to contributed surplus. Upon settlement of the performance share awards by common shares, on the predetermined payment date, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital.

Under the long-term incentive plans, forfeiture rates are assigned in the determination of fair value. Upon vesting, the difference between estimated and actual forfeitures is adjusted through share-based compensation.

Short-term employee benefits

Short-term employee benefit obligations are expensed as the related service is provided. A liability is recognized for the amount expected to be paid under short-term cash bonus or profit-sharing plans if Bonavista has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee, and the obligation can be estimated reliably.

Lease payments

Payments made under operating leases are recognized in profit and loss on a straight-line basis over the term of the lease. Lease incentives received are recognized as an integral part of the total lease expense, over the term of the lease.

Provisions

A provision is recognized if, as a result of a past event, Bonavista has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

Decommissioning liabilities

Bonavista's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning liabilities are measured at the present value of management's best estimate of expenditure required to settle the present obligation at the date of the consolidated statement of financial position. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

Revenues

Revenues from the sale of oil, natural gas and natural gas liquids are recorded when the significant risks and rewards of ownership of the product is transferred to the buyer, which is usually when legal title passes to the external party. This is generally at the time product enters the pipeline. Revenues are measured net of discounts, customs, duties and royalties. With respect to the latter, the Corporation is acting as a collection agent on behalf of others.

Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

Finance income and costs

Finance costs comprise of interest expense on borrowings, unwinding of the discount on provisions and impairment losses recognized on financial assets, fair value losses on financial assets at fair value through profit and loss.

Interest income is recognized as it accrues in profit or loss, using the effective interest method.

Foreign currency gains and losses are reported under finance income or expenses.

Income taxes

Income tax expense comprises current and deferred income taxes. Current and deferred income taxes are recognized in the consolidated statement of income except to the extent that it relates to a business combination, or items recognized directly in equity or in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are not recognized for:

- temporary differences on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss; and
- temporary differences related to investments in subsidiaries to the extent that it is probable that they will not reverse in the foreseeable future; and
- taxable temporary differences arising on the initial recognition of goodwill.

Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

Deferred income tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred income tax asset is recognized for unused tax losses, tax credits and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which they can be utilized. Deferred income tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Net income per share

Basic net income per share is calculated by dividing the profit or loss attributable to common shareholders of Bonavista by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the profit or loss attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as options granted to employees.

3. New accounting policies

Changes in accounting policies

On January 1, 2015, Bonavista adopted a Performance Incentive Award Plan ("PIAs") for directors, officers, certain employees and eligible consultants. Subject to the terms and conditions of the Performance Incentive Award Plan, PIAs granted pursuant to the plan, entitle the holder to be paid thirty-nine months from the date of grant (the "Payment Date"). On the payment date, Bonavista has sole and absolute discretion to settle the PIAs in the form of either cash or common shares, or some combination thereof. Bonavista's current non-binding intention is to settle the PIAs in the form of common shares and has therefore accounted for the PIAs as though they will be equity-settled. Provided that Bonavista maintains this intention to settle the PIAs through the issuance of common shares, the PIAs will continue to be accounted for as equity-settled throughout the vesting period. The number of common shares issued for each PIA granted will also be adjusted for the payments of dividends from the date of grant to the applicable payment date.

The fair value of the PIAs is determined at the date of grant by using the closing price of common shares, adjusted for an estimated forfeiture rate and multiplied by the estimated performance multiplier. The performance multiplier can range from 0 to 2 and is dependent on the performance of the Corporation at the end of the vesting period relative to corporate performance measures determined at the discretion of Bonavista's Board of Directors. The fair value is recognized as share-based compensation expense over the vesting period with a corresponding increase to contributed surplus. Upon settlement of the PIAs by common shares, on the predetermined payment date, the value in contributed surplus pertaining to the awards will be recorded as shareholders' capital.

Future accounting policies

Below is a brief description of new IFRS standards and amendments that are not yet effective and have not been applied in the preparation of these financial statements. There are no other standards or interpretations issued, but not yet adopted, that are anticipated to have a material impact on the Corporation's financial statements.

- On December 18, 2014, the IASB issued amendments to IAS 1, "Presentation of Financial Statements". These amendments will not require significant changes to the Corporation's current practices but are aimed to facilitate improved financial statement disclosures. The amendments are effective for annual periods beginning on or after January 1, 2016 with early adoption permitted. The Corporation intends to adopt these amendments in its financial statements for the annual period beginning on January 1, 2016. The Corporation does not expect these amendments to have a material impact on its financial statements.
- On May 28, 2014, the IASB issued IFRS 15, "Revenue from Contracts with Customers," which replaces IAS 18 "Revenue," IAS 11 "Construction Contracts," and related interpretations. The new standard contains a single model that applies to contracts with customers and two approaches to recognizing revenue: at a point in time or over time. The new standard is effective for annual periods beginning on or after January 1, 2018, with early adoption permitted. The Corporation intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of the adoption of the standard has not yet been determined.
- On July 24, 2014, the IASB issued the complete IFRS 9, "Financial Instruments" to replace IAS 39, "Financial Instruments: Recognition and Measurement". IFRS 9, as amended, includes a principle-based approach for the classification and measurement of financial assets, a single 'expected credit loss' impairment model and a new hedge accounting standard which aligns hedge accounting more closely with risk management. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted if IFRS 9 is adopted in its entirety at the beginning of a fiscal period. The Corporation intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The extent of the impact of the adoption of the standard has not yet been determined.
- On January 13, 2016, the IASB issued IFRS 16, "Leases", which replaces IAS 17 "Leases". The new standard introduces a single recognition and measurement model for leases, which would require the recognition of assets and liabilities for most leases with a term of more than twelve months. The new standard is effective for annual periods beginning on or after January 1, 2019. Early adoption is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the initial adoption date of January 1, 2018. The Corporation intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The extent of the impact of the adoption of the standard has not yet been determined.

4. Financial risk management

Bonavista is exposed to certain market risks that are part of its normal course of business. These market risks include commodity price risk, interest rate risk and foreign exchange risk. To manage its exposure to these market risks, Bonavista has a risk management program in place which includes financial instruments as disclosed in the commodity price risk and foreign exchange risk sections of this note. The objective of Bonavista's risk management program is to mitigate exposure to fluctuations in commodity prices, interest rates and foreign exchange rates to reduce volatility in the Corporation's funds from operations.

Commodity price risk

Bonavista is exposed to commodity price risk as prices received for its oil and natural gas production fluctuate. Commodity prices fluctuate as a result of a number of local and global factors including, supply and demand, inventory levels, weather patterns, pipeline transportation constraints, political stability and economic factors. Bonavista mitigates a portion of the commodity price risk through the use of various financial instrument commodity contracts and physical delivery sales contracts. Bonavista's policy is to enter into commodity price contracts when considered appropriate to a maximum of 70% of forecasted revenues, net of royalties for the subsequent twelve month period and 60% thereafter, provided that no more than 80% of forecasted revenues, net of royalties, from any one product may be hedged, or in the case of electricity, 60% of Bonavista's forecasted net consumption. The term of any commodity hedge executed will be limited to no more than three calendar years subsequent to the current calendar year. Bonavista's management regularly reviews this policy to reflect changes in market conditions.

Financial instrument commodity contracts

As at December 31, 2015, Bonavista entered into the following costless collars to sell natural gas:

Volume		Average Price	Term
10,000	gjs/d	CDN $3.75 - CDN $4.26 - AECO	January 1, 2016 - March 31, 2016
20,000	gjs/d	CDN $3.69 - CDN $4.04 - AECO	January 1, 2016 - December 31, 2016
15,000	gjs/d	CDN $3.00 - CDN $3.29 - AECO	January 1, 2016 - December 31, 2017
10,000	gjs/d	CDN $3.75 - CDN $4.20 - AECO	January 1, 2017 - December 31, 2017
10,550	gjs/d	US $3.90 - US $4.43 - NYMEX	January 1, 2016 - March 31, 2016

As at December 31, 2015, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
20,000	gjs/d	CDN $3.32	Swap - AECO	January 1, 2016 - December 31, 2016
5,000	gjs/d	CDN $3.81	Swap - AECO	January 1, 2016 - March 31, 2016
10,000	gjs/d	CDN $2.17	Swap - AECO	January 1, 2016 - September 30, 2016
20,000	gjs/d	CDN $3.56	Swap - AECO	January 1, 2016 - December 31, 2016
45,000	gjs/d	CDN $3.00	Swap - AECO	January 1, 2016 - December 31, 2017
10,000	gjs/d	CDN $2.60	Swap - AECO	January 1, 2016 - December 31, 2018
20,000	gjs/d	CDN $2.64	Swap - AECO	April 1, 2016 - October 31, 2016
5,000	gjs/d	CDN $3.08	Swap - AECO	October 1, 2016 - December 31, 2016
20,000	gjs/d	CDN $3.27	Swap - AECO	January 1, 2017 - March 31, 2017
20,000	gjs/d	CDN $3.00	Swap - AECO	April 1, 2017 - October 31, 2017
10,550	gjs/d	US $3.50	Swap - NYMEX	January 1, 2017 - March 31, 2017
10,550	gjs/d	US $(0.47)	Swap - AECO Basis	January 1, 2016 - March 31, 2016
10,550	gjs/d	US $(0.60)	Swap - AECO Basis	April 1, 2016 - December 31, 2018
2,500	bbls/d	US 46.2%	Swap - CNWY PN/WTI	January 1, 2016 - March 31, 2016[1]
1,000	bbls/d	US 40%	Swap - CNWY PN/WTI	April 1, 2016 - March 31, 2017[1]
1,000	bbls/d	US $(3.95)	Swap - WTI-MSW	January 1, 2016 - December 31, 2016
500	bbls/d	US $1.50	Swap - WTI-CRW	February 1, 2016 - March 31, 2016
1,500	bbls/d	CDN $78.87	Swap - WTI	January 1, 2016 - December 31, 2016[2]
500	bbls/d	US $65.00	Swap - WTI	January 1, 2016 - December 31, 2016
500	bbls/d	US $65.25	Swap - WTI	July 1, 2016 - June 30, 2017

(1) Conway propane price as a percentage of WTI.
(2) Includes an extendable feature on 500 bbls/d, which at the discretion of the counterparty would continue the term of the contract to December 31, 2017.

Subsequent to December 31, 2015, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
10,000	gjs/d	CDN $2.43	Swap - AECO	April 1, 2016 - October 31, 2016
10,000	gjs/d	CDN $2.65	Swap - AECO	April 1, 2016 - March 31, 2017
500	bbls/d	CDN $60.42	Swap - WTI	February 1, 2016 - December 31, 2016
500	bbls/d	CDN $65.00	Sold Call - WTI	January 1, 2018 - December 31, 2018
1,000	bbls/d	US 55.9%	Swap - MTB BT/WTI	April 1, 2016 - September 30, 2016

As at December 31, 2015, Bonavista entered into the following contracts to purchase electricity:

Volume		Price	Contract	Term
5	mwh	CDN $51.60	Swap - AESO	January 1, 2016 - December 31, 2016
2	mwh	CDN $48.18	Swap - AESO	January 1, 2017 - December 31, 2017

The change in fair value for those natural gas financial instrument commodity contracts in place at December 31, 2015 due to a $0.10 change in the price per thousand cubic feet of natural gas - AECO, would have had an impact of approximately $7.9 million on net income (loss) and comprehensive income (loss) (December 31, 2014 - $10.4 million). The change in fair value for those oil financial instrument commodity contracts in place at December 31, 2015 due to a $1.00 change in the price per barrel of oil - WTI would have had an impact of approximately $1.0 million on net income (loss) and comprehensive income (loss) (December 31, 2014 - $2.1 million).

Financial instrument commodity contracts are recorded on the consolidated statement of financial position 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 income (loss) and comprehensive income (loss). As at December 31, 2015, the fair value recorded in the consolidated statement of financial position for these financial instrument commodity contracts was a net asset of $80.5 million (December 31, 2014 - $153.9 million) of which $63.4 million (December 31, 2014 - $138.6 million) relates to financial instrument commodity contracts with term dates within one year and $17.1 million (December 31, 2014 - $15.3 million) relates to financial instrument commodity contracts with term dates beyond one year. During the year ended December 31, 2015, a net gain of $75.8 million (December 31, 2014 - $123.6 million) was recorded in the consolidated statement of income (loss) and comprehensive income (loss), consisting of a realized gain of $149.2 million (December 31, 2014 - $65.2 million realized loss) and an unrealized loss of $73.4 million (December 31, 2014 - $188.8 million unrealized gain).

Physical purchase and sale contracts

As at December 31, 2015, Bonavista entered into the following physical contracts to sell natural gas:

Volume		Price	Term
50,000	gjs/d	CDN $3.42	January 1, 2016 - December 31, 2016[1]
10,000	gjs/d	CDN $2.52	April 1, 2016 - June 30, 2016[2]
10,000	gjs/d	CDN $2.96	April 1, 2016 - October 31, 2016[2]
20,000	gjs/d	CDN $3.23	January 1, 2017 - December 31, 2017[2][3]

(1) Includes an extendable feature which at the discretion of the counterparty would continue the term of the contract to December 31, 2017.
(2) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 10,000 gjs/d on the last trade date of each month for the duration of the contract.
(3) Includes an extendable feature which at the discretion of the counterparty would continue the term of the contract on 10,000 gjs/d to December 31, 2018.

Foreign exchange risk

Bonavista is exposed to foreign currency fluctuations as oil and natural gas prices are referenced to US dollar denominated prices. Bonavista has mitigated some of this foreign exchange risk by entering into fixed CDN dollar oil and natural gas swaps and collars as outlined in the commodity price risk section above. In addition, Bonavista has US dollar denominated senior unsecured notes and interest obligations of which future cash repayments are directly impacted by the CDN dollar to the US dollar exchange rate.

To fix the foreign exchange rate on a portion of the US dollar denominated senior unsecured notes, Bonavista has entered into the following contracts to purchase US dollars at predetermined rates on settlement dates that coincide with Bonavista's US dollar debt repayment commitments.

Settlement date	Contract	Notional US$	CDN$/US$
June 6, 2016	US$ purchased forward	$12,500,000	1.2220
June 5, 2017	US$ purchased forward	$12,500,000	1.2234
November 2, 2017	US$ purchased forward	$ 60,000,000	1.1089
November 2, 2020	US$ purchased forward	$160,000,000	1.1494
October 25, 2021	US$ purchased forward	$150,000,000	1.2297
November 2, 2022	US$ purchased forward	$16,500,000	0.9950

Holding all other variables constant, a $0.01 change in the CDN$/US$ exchange rate at December 31, 2015 would have had an impact of approximately $0.2 million on net income (loss) and comprehensive income (loss) (December 31, 2014 - $0.9 million). The fair value recorded in the consolidated statement of financial position for these financial instrument contracts as at December 31, 2015 was a net asset of $70.8 million (December 31, 2014 - $16.0 million) of which $2.0 million (December 31, 2014 - nil) relates to a financial instrument contract with a term date within one year and $68.8 million (December 31, 2014 - $16.0 million) relates to financial instrument contracts with term dates beyond one year. For the year ended December 31, 2015, an unrealized gain of $54.7 million was recorded on the consolidated statement of income (loss) and comprehensive income (loss) within finance income (December 31, 2014 - $8.0 million unrealized gain).

Interest rate risk

Bonavista is exposed to interest rate risk on any amount outstanding on its Canadian bank credit facility. Bonavista manages interest rate risk by having both fixed interest rates on senior unsecured notes and floating interest rates on outstanding bank debt.

Credit risk

Credit risk is the risk of financial loss to Bonavista if a customer or counterparty to a financial instrument fails to meet its contractual obligation and arises, primarily from joint operations partners, marketers and financial intermediaries.

Bonavista's accounts receivable are with customers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. Bonavista routinely assesses the financial strength of its customers. Bonavista may be exposed to certain losses in the event of non-performance by counterparties to financial instrument contracts. Bonavista mitigates this risk by entering into transactions with highly rated financial institutions.

The carrying amount of accounts receivable represents the maximum credit exposure. As at December 31, 2015 Bonavista's receivables consisted of $54.3 million of receivables from oil and natural gas marketers of which substantially all has been collected subsequent to December 31, 2015 and $16.0 million from joint operations partners of which $4.1 million has been subsequently collected. As at December 31, 2015 Bonavista has $3.1 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. As the operator of properties, Bonavista has the ability to withhold production from joint operations partners, who are in default of amounts owing. Bonavista does not have an allowance for doubtful accounts as at December 31, 2015 and did not provide for any doubtful accounts during the year ended December 31, 2015.

Liquidity risk

Liquidity risk is the risk that Bonavista will encounter difficulty in meeting obligations associated with the financial liabilities. Bonavista's financial liabilities consist of accounts payable and accrued liabilities, dividends payable, financial instruments contracts, bank debt, and senior unsecured notes. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities, and capital expenditures. Bonavista processes invoices within a normal payment period.

Accounts payable and accrued liabilities have contractual maturities of less than one year. Dividends payable are declared on a monthly basis and are dependent upon a number of factors including current and future commodity prices, foreign exchange rates, Bonavista's commodity hedging program, current operations and future investment opportunities. Financial instrument contracts have contractual maturities of less than three years on all commodity contracts and range from six months to seven years on foreign exchange contracts. Bonavista's four year revolving credit facility, as outlined in note 11, may at the request of the Corporation with the consent of the lenders, be extended on an annual basis beyond the existing term. Bonavista also has a series of senior unsecured notes outstanding with fixed interest rates, as outlined in note 11, which range in maturities from June 4, 2016 to May 23, 2025. Bonavista also maintains and monitors a certain level of cash flow, which is used to partially finance all operating, investing and capital expenditures.

Financial instrument classification and measurement

Bonavista's financial instruments include marketable securities, accounts receivable, financial instrument commodity contracts, financial instrument contracts, accounts payable and accrued liabilities, dividends payable and long-term debt. Bonavista classifies the fair value of these financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuation in this level are those with inputs for the asset or liabilities that are not based on observable market data.

Bonavista's marketable securities have been classified as Level 1 measurements and its financial instrument commodity contracts, financial instrument contracts, bank debt and senior unsecured notes are classified as Level 2 measurements. To estimate the fair value of these financial instruments Bonavista uses quoted market prices when available or fair-value estimates from third-party valuation models that use observable market data. Bonavista does not have any fair value measurements classified as Level 3. Bonavista does not have any financial assets or financial liabilities that are subject to offsetting arrangements.

The fair market value recorded on the consolidated statements of financial position for these financial instrument contracts were as follows:

	December 31, 2015	December 31, 2014
($ thousands)		
Current assets		
Marketable securities(1)	**102**	814
Financial instrument commodity contracts(2)	**66,213**	140,271
Financial instrument contracts(2)	**2,013**	—
Long-term assets		
Financial instrument commodity contracts(2)	**19,390**	17,680
Financial instrument contracts(2)	**68,754**	16,025
Current liabilities		
Financial instrument commodity contracts(2)	**(2,811)**	(1,693)
Long-term liabilities		
Financial instrument commodity contracts(2)	**(2,289)**	(2,385)
Net asset	**151,372**	170,712

(1) Level 1
(2) Level 2

Bonavista's bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value. The fair market value of Bonavista's senior unsecured notes as at December 31, 2015 is approximately $1.0 billion (December 31, 2014 - $924.5 million), compared to a carrying amount of $995.7 million (December 31, 2014 - $887.9 million).

5. Capital Management

Bonavista's objective when managing capital is to create value for shareholders by consistently aligning its capital program and dividends with funds from operations. While world commodity prices continue to present a challenging environment for the North American energy sector, Bonavista remains committed to preserving financial flexibility, future asset value and the prudent use of debt. This has been accomplished by way of reductions to Bonavista's capital and dividend programs to align with funds from operations.

Bonavista considers its capital structure to include working capital (excluding associated assets and liabilities from financial instrument commodity contracts and decommissioning liabilities), bank credit facility, senior unsecured notes and shareholders' equity. Bonavista 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, senior unsecured notes and adjusted working capital, divided by funds from operations for the most recent calendar quarter, annualized (multiplied by four). This ratio may increase at certain times as a result of acquisitions or low commodity prices. As at December 31, 2015, Bonavista's ratio of net debt to fourth quarter annualized funds from operations was 3.4 to 1 (December 31, 2014 - 2.1 to 1).

To facilitate the management of this ratio, Bonavista prepares annual funds from operations and capital expenditure budgets, which are updated as necessary, and are reviewed and periodically approved by Bonavista's Board of Directors. The Corporation manages its capital structure and makes adjustments by continually monitoring its business conditions, including: the current economic conditions; the risk characteristics of Bonavista's 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 differentials, royalties, operating costs and transportation costs.

To maintain or adjust the capital structure, Bonavista 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 Corporation's lenders; the availability of other sources of debt with different characteristics than the existing bank debt; the sale of assets; the monetization of financial instrument contracts; limiting the size of the capital expenditure program; issuance of new equity if available on favourable terms; and its level of dividends payable to its shareholders. Bonavista shareholders' capital is not subject to external restrictions, however, the Corporation's bank credit facility and senior unsecured notes do contain financial covenants that are outlined in note 11 of the consolidated financial statements.

The following table reconciles funds from operations to its nearest measure prescribed by IFRS, cash flow from operating activities.

	Three months ended December 31		Years ended December 31	
Calculation of Funds from Operations	**2015**	2014	**2015**	2014
($ thousands)				
Cash flow from operating activities	**126,735**	139,349	**406,290**	593,824
Interest expense	**(12,860)**	(11,060)	**(49,716)**	(43,921)
Decommissioning expenditures	**3,281**	9,944	**18,925**	32,026
Changes in non-cash working capital	**(21,364)**	(2,388)	**9,852**	(20,824)
Funds from operations[(1)]	**95,792**	135,845	**385,351**	561,105

(1) Funds from operations as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities.

The following table represents Bonavista's ratio of net debt to funds from operations as follows:

Net Debt to Funds from Operations	**Year ended December 31, 2015**	Year ended December 31, 2014
($ thousands)		
Long Term Debt	**1,231,031**	989,671
Adjusted working capital deficiency[(1)]	**79,632**	165,751
Total net debt[(2)]	**1,310,663**	1,155,422
Funds from operations fourth quarter annualized	**383,168**	543,380
Total net debt to funds from operations	**3.4:1**	2.1:1
Funds from operations for the year ended December 31, 2015	**385,351**	561,105
Total net debt to funds from operations	**3.4:1**	2.1:1

(1) Adjusted working capital deficiency as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measure for other entities. Adjusted working capital deficiency excludes associated assets or liabilities for financial instrument commodity contracts and decommissioning liabilities.

(2) Total net debt as presented does not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measure with other entities.

6. Finance costs and income

($ thousands)	**Year ended December 31, 2015**	Year ended December 31, 2014
Finance costs		
Accretion of decommissioning liabilities	**10,107**	10,938
Accretion of other liabilities	**1,425**	1,568
Interest on bank debt	**10,503**	9,196
Interest on notes payable	**40,745**	36,013
Unrealized loss on foreign exchange	**157,850**	68,033
Unrealized loss on marketable securities	**712**	1,831
Total finance costs	**221,342**	127,579
Finance income		
Unrealized gain on financial instrument contracts	**(54,742)**	(8,002)
Total finance income	**(54,742)**	(8,002)
Net finance costs	**166,600**	119,577

7. Supplemented cash flow information

($ thousands)	**Year ended December 31, 2015**	Year ended December 31, 2014
Cash provided by (used for):		
Accounts receivable	**32,562**	18,954
Prepaid expenses	**1,192**	(2,203)
Other assets	**6,081**	(7,231)
Accounts payable and accrued liabilities, net of interest accrual	**(100,168)**	17,527
	(60,333)	27,047
Related to:		
Operating activities	**(9,852)**	20,824
Investing activities	**(50,481)**	6,223
	(60,333)	27,047

8. Property, plant and equipment

($ thousands)	Oil and natural gas properties	Facilities	Other Assets	Total
Cost				
Balance as at December 31, 2013	4,471,963	538,578	24,558	5,035,099
Additions	581,261	38,683	3,018	622,962
Acquisitions	136,138	31,988	—	168,126
Transfers from exploration and evaluation assets	64,558	—	—	64,558
Changes in decommissioning liabilities	179,000	—	—	179,000
Dispositions	(398,557)	(45,885)	—	(444,442)
Balance as at December 31, 2014	5,034,363	563,364	27,576	5,625,303
Additions	**298,880**	**14,970**	**1,203**	**315,053**
Acquisitions	**9,052**	**3,235**	**—**	**12,287**
Transfers from exploration and evaluation assets	**22,930**	**—**	**—**	**22,930**
Changes in decommissioning liabilities	**32,304**	**—**	**—**	**32,304**
Dispositions	**(142,507)**	**(22,895)**	**—**	**(165,402)**
Balance as at December 31, 2015	**5,255,022**	**558,674**	**28,779**	**5,842,475**
Depletion, depreciation, amortization and impairment				
Balance as at December 31, 2013	(1,094,558)	(86,009)	(9,188)	(1,189,755)
Depletion, depreciation, amortization and impairment	(629,341)	(26,554)	(3,390)	(659,285)
Dispositions	145,302	11,831	—	157,133
Balance as at December 31, 2014	(1,578,597)	(100,732)	(12,578)	(1,691,907)
Depletion, depreciation, amortization and impairment	**(1,135,273)**	**(26,420)**	**(2,979)**	**(1,164,672)**
Dispositions	**71,119**	**7,320**	**—**	**78,439**
Balance as at December 31, 2015	**(2,642,751)**	**(119,832)**	**(15,557)**	**(2,778,140)**
Net book value as at December 31, 2015	**2,612,271**	**438,842**	**13,222**	**3,064,335**
Net book value as at December 31, 2014	3,455,766	462,632	14,998	3,933,396

For the year ended December 31, 2015, Bonavista capitalized $7.7 million (December 31, 2014 - $8.5 million) of direct general and administrative expenses.

During the year ended December 31, 2015, Bonavista successfully disposed of certain non-core petroleum and natural gas rights, through asset exchanges and other property dispositions for total proceeds of $100.1 million resulting in a before tax gain on sale of property, plant and equipment of $19.9 million and a $14.5 million before tax gain on sale of exploration and evaluation assets. During the comparative year ended December 31, 2014, proceeds of $289.4 million were received from dispositions of several non-core properties including, mature heavy oil properties in Northern Alberta, resulting in a before tax gain on sale of property plant and equipment of $61.8 million and a before tax loss on exploration and evaluation assets of $5.9 million.

Impairment Testing

As a result of a significant and sustained decline in forward commodity benchmark prices for oil, natural gas and natural gas liquids during 2015 as compared to January 1, 2015 benchmark prices, impairment tests were carried out on each of Bonavista's CGUs, resulting in a total property, plant and equipment ("PP&E") impairment of $809.0 million (December 31, 2014 - $300.0 million). The recoverable amount of each CGU as at December 31, 2015 was determined using value in use, with assumptions noted below.

Impairments were recorded in the following CGUs for the year ended December 31, 2015:

- British Columbia CGU, located mainly in northeast British Columbia near Fort St. John, composed of primarily natural gas and natural gas liquids producing assets, recorded a $83.0 million (December 31, 2014 - $85.0 million) PP&E impairment. The estimated recoverable amount of the British Columbia CGU as at December 31, 2015 was $109.9 million.
- Central Alberta CGU, composed of primarily natural gas and natural gas liquids producing assets, recorded a $364.0 million (December 31, 2014 - $105.0 million) PP&E impairment. The estimated recoverable amount of the Central Alberta CGU as at December 31, 2015 was $1,289.7 million.

- North Central Alberta CGU, located between Edmonton and Fox Creek, Alberta, composed of primarily natural gas producing assets, recorded a $194.0 million (December 31, 2014 - nil) PP&E impairment. The estimated recoverable amount of the North Central Alberta CGU as at December 31, 2015 was $662.5 million.
- South Central Alberta CGU, composed of primarily natural gas and natural gas liquids producing assets, recorded a $105.0 million (December 31, 2014 - nil) PP&E impairment. The estimated recoverable amount of the South Central Alberta CGU as at December 31, 2015 was $373.5 million.
- Southern Alberta CGU, composed of primarily light oil producing assets, recorded a $15.0 million (December 31, 2014 - $60.0 million) PP&E impairment. The estimated recoverable amount of the Southern Alberta CGU as at December 31, 2015 was $119.3 million.
- Eastern Alberta CGU, composed of primarily light oil and natural gas producing assets, recorded a $48.0 million (December 31, 2014 - $50.0 million) PP&E impairment. The estimated recoverable amount of the Eastern Alberta CGU as at December 31, 2015 was $10.4 million.

The proved plus probable reserve values were based on Bonavista's December 31, 2015 reserve report as prepared by its independent reserve engineer GLJ Petroleum Consultants.The recoverable amount of the CGUs were estimated based on proved plus probable reserve values using before-tax discount rates specific to the underlying composition of reserve categories and risk profile residing in each CGU. The discount rates used ranged from 10 to 12 percent. Key input estimates used in the determination of cash flows from Bonavista's oil and gas reserves included: quantities of reserves and future production; forward commodity pricing as prepared by the average of four independent reserve engineer evaluators; development costs; operating costs; royalty obligations; abandonment costs; and discount rates.

The results of Bonavista's impairment tests are sensitive to changes in any of the key estimates of which changes could decrease or increase the recoverable amounts of assets and result in additional impairment charges or recovery of impairment charges. If a before-tax discount rate of 8 percent had been used in all reserve categories in each of Bonavista's CGUs in the determination of the recoverable amounts, the impairment charge for the year ended December 31, 2015, would have been reduced by $535.0 million to $274.0 million. If a before-tax discount rate of 12 percent had been used on all reserve categories in each of Bonavista's CGUs, in the determination of the recoverable amounts, Bonavista would have recorded an additional impairment charge of $211.0 million for the year ended December 31, 2015. The impairments recorded for the year ended December 31, 2015 may be reversed at such time that the fair value of the impaired CGU increases.

Forward Commodity Prices used in the December 31, 2015 Impairment Test(1)

Year	Edmonton Light Crude Oil	WTI Oil	AECO Gas	Foreign Exchange Rate
	(CDN$/bbl)	(US$/bbl)	(CDN$/MMBtu)	(US$/CDN$)
2016	54.75	44.00	2.54	0.736
2017	64.26	53.51	3.07	0.768
2018	71.49	61.90	3.38	0.801
2019	80.43	69.84	3.71	0.813
2020	85.75	75.01	3.93	0.825
2021	90.41	79.38	4.13	0.831
2022	95.76	83.84	4.33	0.831
2023	99.47	87.00	4.52	0.831
2024	101.45	88.93	4.70	0.831
2025	103.34	90.58	4.81	0.831
Thereafter	1.9%/year	1.9%/year	1.9%/year	0.831

(1) The average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule and Deloitte Research Evaluation & Advisory price forecasts, effective January 1, 2016.

Forward Commodity Prices used in the December 31, 2014 Impairment Test[1]

Year	Edmonton Light Crude Oil	WTI Oil	AECO Gas	Foreign Exchange Rate
	(CDN$/bbl)	(US$/bbl)	(CDN$/MMBtu)	(US$/CDN$)
2015	64.71	62.50	3.31	0.850
2016	80.00	75.00	3.77	0.875
2017	85.71	80.00	4.02	0.875
2018	91.43	85.00	4.27	0.875
2019	97.14	90.00	4.53	0.875
2020	102.86	95.00	4.78	0.875
2021	106.18	98.54	5.03	0.875
2022	108.31	100.51	5.28	0.875
2023	110.47	102.52	5.53	0.875
2024	112.67	104.57	5.71	0.875
Thereafter	2.0%/year	2.0%/year	2.0%/year	0.875

(1) Represents forecasted assumptions as at January 1, 2015 as prepared by Bonavista's independent reserves evaluator, GLJ Petroleum Consultants.

9. Goodwill and Exploration and evaluation assets

	Goodwill	**Exploration and evaluation assets**
($ thousands)		
Balance as at December 31, 2013	11,225	222,085
Additions	—	29,391
Acquisitions	—	20,887
Dispositions	—	(18,312)
Transfers to property, plant and equipment	—	(64,558)
Impairment	(11,225)	—
Balance as at December 31, 2014	—	189,493
Additions	**—**	**7,823**
Acquisitions	**—**	**59,117**
Dispositions	**—**	**(19,965)**
Transfers to property, plant and equipment	**—**	**(22,930)**
Impairment	**—**	**(3,344)**
Balance as at December 31, 2015	**—**	**210,194**

Exploration and evaluation ("E&E") assets consist of Bonavista's exploration projects which are pending the determination of proved or probable reserves and production. Additions represent Bonavista's share of costs incurred on E&E assets during the year.

Impairment Testing

As at December 31, 2015, Bonavista determined that indicators of impairment existed with respect to its E&E assets and an impairment analysis was performed. For the purpose of impairment testing, the recoverable amounts of E&E assets were determined using internal estimates of the fair value of undeveloped land and seismic assets based principally on recent and relevant land sales. For the year ended December 31, 2015, Bonavista recognized impairment of $3.3 million (December 31, 2014 - nil) on E&E assets related to its Southern Alberta CGU where the carrying value exceeded the recoverable amount. The impairment was recorded in depletion, depreciation, amortization and impairment in Bonavista's consolidated statement of income (loss) and comprehensive (loss). The impairment recorded at December 31, 2015 may be reversed at such time that the fair value of the impaired E&E assets increases.

As at December 31, 2015, Bonavista had no goodwill assets recorded. For the year ended December 31, 2014, Bonavista recorded a goodwill impairment charge of $11.2 million. The goodwill impairment was recorded in Bonavista's Central Alberta CGU.

10. Shareholders' equity

Bonavista is authorized to issue an unlimited number of common shares without nominal or par value, an unlimited number of exchangeable shares without nominal or par value and 10,000,000 preferred shares, issuable in series.

The holders of common shares are entitled to receive dividends as declared by Bonavista and are entitled to one vote per share. Dividends declared for the year ended December 31, 2015 were $0.37 per share (December 31, 2014 - $0.84 per share). On February 17, 2016, the Board of Directors declared a dividend of $0.01 per common share, payable in cash to shareholders of record on February 29, 2016. The dividend payment date is March 15, 2016. Effective April 1, 2016, our Board of Directors has approved a 67% reduction in the dividend to $0.01 per share per quarter.

On December 31, 2011 and May 3, 2012, Bonavista adopted a dividend reinvestment plan ("DRIP") and stock dividend plan (“SDP”), respectively. The DRIP and SDP provide eligible holders of common shares the option to reinvest cash dividends into common shares issued either from treasury at a five per cent discount to the prevailing average market price or acquired through the facilities of the Toronto Stock Exchange at prevailing market rates with no discount. On May 1, 2014, the Board of Directors suspended the DRIP and SDP for the remainder of 2014. The reinstatement of the DRIP and SDP at a future date is at the discretion of the Corporation's Board of Directors.

The exchangeable shares of Bonavista are exchangeable into common shares based on the exchange ratio, which is adjusted monthly, to reflect dividends paid on common shares. As a result, cash dividends are not paid on exchangeable shares. The holders of exchangeable shares are entitled to one vote times the exchange ratio for each exchangeable share.

a. Issued and outstanding

Common shares

	Common Shares	**Amount**
	(thousands)	($ thousands)
Balance as at December 31, 2013	186,962	2,228,210
Issued for cash	12,100	200,860
Issue costs, net of future tax benefit	—	(6,280)
Issued on conversion of exchangeable shares	1,499	34,568
Issued pursuant to the dividend reinvestment and stock dividend plans	1,748	26,075
Issued upon exercise of stock options and common shares incentive rights	387	4,154
Conversion of incentive and restricted share awards, net of future tax	1,064	148
Share-based compensation	—	26,271
Balance as at December 31, 2014	203,760	2,514,006
Issued on conversion of exchangeable shares	**8,342**	**178,350**
Conversion of incentive and restricted share awards	**1,877**	**—**
Share-based compensation	**—**	**23,655**
Balance as at December 31, 2015	**213,979**	**2,716,011**

Exchangeable shares

	Year ended December 31, 2015		Year ended December 31, 2014	
	Exchangeable Shares	**Amount**	Exchangeable Shares	Amount
	(thousands)	($ thousands)	(thousands)	($ thousands)
Balance, beginning of year	9,476	272,900	10,676	307,468
Exchanged for common shares	**(6,193)**	**(178,350)**	(1,200)	(34,568)
Balance, end of year	**3,283**	**94,550**	9,476	272,900
Exchange ratio, end of year	1.39313	—	1.28262	—
Common shares issuable on exchange	**4,573**	**94,550**	12,154	272,900

The holders of Bonavista's exchangeable shares shall be entitled to notice of, to attend at, and to that number of votes equal to the number of exchangeable shares held multiplied by the exchange ratio in effect at the meeting record date at any meeting of the shareholders of Bonavista. In accordance with the provisions of the Corporation’s exchangeable shares, Bonavista may require, at any time, the exchange of that number of the Corporation’s exchangeable shares as determined by the Board of Directors on the basis of the exchange ratio in effect on the date set by Bonavista (the “Compulsory Exchange Date”). On and after the applicable Compulsory Exchange Date, the holders of Bonavista's exchangeable shares called for exchange shall cease to be holders of such Corporation's exchangeable shares and shall not be entitled to exercise any of the rights of holders in respect thereof, other than; (i) the right to receive their proportionate part of the common shares; and (ii) the right to receive any declared and unpaid dividends on such common shares.

b. Share-based compensation

Bonavista has option, incentive award and performance incentive award programs, collectively the "long-term incentive plans", that entitle officers, directors, employees and certain consultants to purchase and receive shares in the Corporation. The number of common shares awarded under long-term incentive plans is limited to 8% of the aggregate number of issued and outstanding equivalent shares of the Corporation.

Share-based compensation expense recognized during the year ended December 31, 2015 was $17.2 million (December 31, 2014 - $20.4 million). For the year ended December 31, 2015, $1.7 million of share-based compensation expense was capitalized to property, plant and equipment (December 31, 2014 - $2.2 million). As at December 31, 2015, the balance of contributed surplus attributable to share-based compensation awards was $52.8 million (December 31, 2014 - $57.6 million).

Stock option and common share incentive rights plans

Upon conversion to a corporation, the stock option plan of Bonavista was established and the common share rights incentive plan (formerly the trust unit rights incentive plan of the Trust) was amended. The amended plan provided that all rights to acquire trust units became rights to acquire common shares. All new rights granted after December 31, 2010 were granted under the stock option plan.

Directors, officers, employees and certain consultants of Bonavista are eligible to receive options under the stock option plan. Grants made under the stock option plan vest evenly over a three year period and expire three years after each vesting date, whereas grants made under the amended common share rights incentive plan vest over a four year period and expire two years after each vesting date.

Bonavista estimates the fair value of share options granted using a Black-Scholes option pricing model. The following average assumptions were used to arrive at the estimated fair value for those options granted during the year ended December 31, 2014. Bonavista did not grant any awards under the stock option plan during the year ended December 31, 2015.

Weighted average for the year ended	December 31, 2014
Dividend yield	5.83%
Volatility	28.30%
Risk-free interest rate	1.40%
Forfeiture rate(1)	9.55%
Expected life	3.8

(1) The estimated forfeiture rate is adjusted for actual forfeitures throughout the vesting period.

The following table summarizes the stock option and common share incentive rights outstanding and exercisable under the plans at December 31:

	Stock Options/Common Share Incentive Rights	**Weighted Average Exercise Price**
		($ per share)
Balance as at December 31, 2013	6,798,478	19.52
Granted	2,964,210	14.74
Exercised	(387,010)	(10.73)
Expired and forfeited	(1,335,896)	(19.36)
Reduction in exercise price	—	(0.14)
Balance as at December 31, 2014	8,039,782	18.08
Expired, forfeited and cancelled	**(7,642,493)**	**(18.05)**
Reduction in exercise price	**—**	**(0.57)**
Balance as at December 31, 2015	**397,289**	**18.05**
Exercisable as at December 31, 2015	**331,558**	**18.60**

During the year ended December 31, 2015, Bonavista's employees voluntarily surrendered 6.5 million options. As at December 31, 2015 there were 0.3 million stock options outstanding (December 31, 2014 - 7.5 million) of which 0.2 million were exercisable (December 31, 2014 - 3.3 million) and 0.1 million common share incentive rights outstanding (December 31, 2014 - 0.5 million) of which all were exercisable (December 31, 2014 - 0.5 million).

The range of exercise prices of the outstanding stock option and common share incentive rights plans is as follows:

	Outstanding			Exercisable	
Range of exercise prices	**Number outstanding**	**Weighted average remaining contractual life (years)**	**Weighted average exercise price**	**Number exercisable**	**Weighted average exercise price**
($ per share)			($ per share)		($ per share)
9.79 - 15.98	144,616	2.06	14.65	114,835	14.86
15.99 - 17.73	163,945	1.48	17.16	127,995	17.37
17.74 - 28.96	88,728	0.89	25.22	88,728	25.22
9.79 - 28.96	397,289	1.56	18.05	331,558	18.60

Incentive and restricted share award incentive plans

Bonavista's incentive and restricted share award incentive plans provide compensation in relation to a notional number of underlying common shares to directors, officers, employees and certain consultants. Awards granted between December 31, 2010 and May 2, 2013 were granted under the restricted share award incentive plan. On May 2, 2013 the restricted share award incentive plan was replaced by the incentive award plan.

Vesting arrangements are within the discretion of Bonavista's Board of Directors, but all awards vest evenly over a period of three years from the date of grant. On the vesting date, the holder will receive, in the case of incentive awards, cash or equivalent common shares for each incentive award and equivalent common shares for each restricted share award, including dividends made on the common shares from the date of the grant to and including the vesting date, net of the statutory withholding tax.

The fair value of incentive and restricted share awards is assessed on the grant date factoring in the weighted average trading price of the five days preceding the grant date and expected dividends. This fair value is recognized as share-based compensation expense over the vesting period with a corresponding increase to contributed surplus. Upon the conversion of the restricted share awards or the settlement of the incentive awards by common shares, on the predetermined vesting dates, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital.

The following table summarizes the incentive and restricted share award incentive plans outstanding at December 31:

	Incentive and Restricted Share Awards
Balance as at December 31, 2013	2,457,085
Granted	1,541,632
Reinvestment(1)	164,402
Exercised	(1,063,636)
Forfeited	(337,312)
Balance as at December 31, 2014	2,762,171
Granted	**1,342,537**
Reinvestment(1)	**231,126**
Exercised	**(1,876,647)**
Forfeited	**(400,097)**
Balance as at December 31, 2015	**2,059,090**

(1) Reinvestment of dividends earned during the period outstanding.

Performance incentive award plan

On January 1, 2015, Bonavista adopted a Performance Incentive Award Plan ("PIAs") for directors, officers, certain employees and eligible consultants. The PIAs vest thirty-nine months from the initial date of grant and the number of common shares issued for each PIA granted is subject to a performance multiplier ranging from 0 to 2. The payout multiplier is dependent on the performance of Bonavista at the end of the vesting period relative to corporate performance measures determined at the discretion of Bonavista's Board of Directors. The number of common shares issued for each PIA granted is also adjusted for the payment of dividends from the date of grant to the payment date. On the payment date, Bonavista has sole and absolute discretion to settle the PIAs in the form of either cash or common shares, or some combination thereof, however, it is Bonavista's intention to settle the PIAs in the form of common shares.

The fair value of PIAs is determined at the date of grant by using the closing price of common shares, multiplied by the estimated performance multiplier. A performance multiplier of 1 has been assumed for PIAs outstanding at December 31, 2015. Fluctuations in share-based compensation expense may occur due to changes in estimates of performance outcomes. The amount of share-based compensation expense is reduced by an estimated forfeiture rate, which has been estimated at 7.05% for outstanding awards. The estimated weighted average fair value of PIAs granted during the year ended December 31, 2015 was $7.26 per award.

	Performance Incentive Awards
Balance as at December 31, 2014	—
Granted	**867,193**
Reinvestment[1]	**62,369**
Forfeited	**(35,639)**
Balance as at December 31, 2015	**893,923**

(1) Reinvestment of dividends earned during the period outstanding.

c. Per share amounts

The following table summarizes the weighted average common shares and exchangeable shares used in calculating net income or loss per equivalent share:

	Year ended December 31, 2015	Year ended December 31, 2014
(thousands)		
Common shares	**207,564**	195,686
Exchangeable shares converted at the exchange ratio	**10,096**	13,033
Basic equivalent shares	**217,660**	208,719
Stock option and common share incentive rights	**—**	12
Incentive and restricted share awards	**1,632**	2,226
Performance incentive awards	**825**	—
Diluted equivalent shares	**220,117**	210,957

11. Long-term debt

	December 31, 2015	December 31, 2014
($ thousands)		
Bank credit facility	**272,056**	154,368
Senior unsecured notes	**993,575**	885,303
Total long-term debt	**1,265,631**	1,039,671
Current portion of long-term debt	**34,600**	50,000
Long-term portion of long-term debt	**1,231,031**	989,671

a. Bank credit facility

On September 10, 2015, Bonavista amended and renewed its existing bank credit facility of $600 million provided by a syndicate of 11 domestic and international banks to a maturity date of September 10, 2019. The amendments made to the bank credit facility pertain to the applicable banks' prime rate and stamping fee for advances made under the facility. Bonavista also has in place a $50 million demand working capital facility, which is subject to the same covenants as the credit facility.

The credit facility is a four year revolving credit and may, at the request of Bonavista with the consent of the lenders, be extended on an annual basis beyond the existing term. There is an accordion feature providing that at any time during the term, on participation of any existing or additional lenders, Bonavista can increase the facility by $250 million.

The credit 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 and accordingly the fair market value approximates the carrying value. The average effective interest rate for bank debt outstanding for the year ended December 31, 2015 was approximately 3.8% (December 31, 2014 - 3.2%). As at December 31, 2015, Bonavista had $325.8 million of unused borrowing capacity on its bank credit facility (December 31, 2014 - $442.8 million).

Under the terms of the bank credit facility, Bonavista has provided the covenant that its: (i) consolidated senior debt borrowing will not exceed three and one half times net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment; (ii) consolidated total debt will not exceed three and one half times of consolidated net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment; and (iii) consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated shareholder’s equity of the Corporation, in all cases calculated based on a rolling prior four quarters. Bonavista’s consolidated senior debt and consolidated total debt were the same at December 31, 2015, including the Corporation's senior unsecured notes issued under the master shelf agreement, senior unsecured notes not subject to the master shelf agreement and the bank credit facility. Bonavista's consolidated senior debt may differ from total debt in instances when the Corporation issues senior subordinated debt or enters into a significant capital lease obligation or guarantee.

As at December 31, 2015, Bonavista was in compliance with all covenants under its bank credit facility.

b. Senior unsecured notes issued under a master shelf agreement

Bonavista 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 rate corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. In 2010, Bonavista drew down US$50 million on the master shelf agreement with a coupon rate of 4.86% with US$25 million maturing on June 4, 2016 and the remaining US$25 million maturing on June 4, 2017.

Bonavista increased its existing master shelf agreement from US$125 million to US$150 million allowing the Corporation to draw an additional US$100 million in notes at a rate equal to the related US treasury rate corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. On April 25, 2013, the Corporation drew down US$100 million on the master shelf agreement with a coupon rate of 3.80% and a maturity date of April 25, 2025. Under the terms of the master shelf agreement, Bonavista has provided similar significant covenants that exist under the bank credit facility.

c. Senior unsecured notes not subject to the master shelf agreement

On November 2, 2010, October 25, 2011 and May 23, 2013 Bonavista issued the following senior unsecured notes by way of a private placement. Under the terms of the senior unsecured notes, Bonavista has provided similar significant covenants that exist under the bank credit facility.

Bonavista's senior unsecured notes, including those senior unsecured notes issued under the master shelf agreement, bear fixed interest rates, with a weighted average rate of 4.1% for the years ended December 31, 2015 and 2014. The senior unsecured notes have a five year weighted average life with the majority of the debt repayments due in 2020 and thereafter.

The terms and coupon rates of the senior unsecured notes, not subject to the master shelf agreement, are summarized below:

Issued Date	**Principal**		**Coupon Rate**	**Maturity Dates**
November 2, 2010	US	$90.0 million	3.66%	November 2, 2017
November 2, 2010	US	$160.0 million	4.37%	November 2, 2020
November 2, 2010	US	$50.0 million	4.47%	November 2, 2022
October 25, 2011	US	$150.0 million	4.25%	October 25, 2021
May 23, 2013	US	$85.0 million	3.68%	May 23, 2023
May 23, 2013	CDN	$20.0 million	4.09%	May 23, 2023
May 23, 2013	US	$20.0 million	3.78%	May 23, 2025

As at December 31, 2015, Bonavista was in compliance with all covenants under its senior unsecured notes issued under the master shelf agreement and senior unsecured notes not subject to the master shelf agreement.

12. Decommissioning liabilities

Bonavista's decommissioning liabilities results from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. Bonavista estimates the net present value of its total decommissioning liabilities to be $488.9 million as at December 31, 2015 (December 31, 2014 - $498.0 million), based on an estimated total future undiscounted liability of approximately $1.1 billion (December 31, 2014 - $1.3 billion). At December 31, 2015 management estimates expenditures required to settle the liability will be made over the next 53 years with the majority of payments being made in years 2046 to 2068. A risk-free rate of approximately 2.2% (December 31, 2014 - 2.3%) based on the Bank of Canada's long-term risk-free bond rate and an inflation rate of 1.8% (December 31, 2014 - 2.0%) were used to calculate the present value of the decommissioning liability as at December 31, 2015.

($ thousands)	**Year ended December 31, 2015**	Year ended December 31, 2014
Balance, beginning of year	497,982	406,487
Accretion expense	**10,107**	10,938
Liabilities incurred	**6,058**	7,587
Liabilities acquired	**1,828**	2,405
Liabilities disposed	**(40,453)**	(76,409)
Liabilities settled	**(18,925)**	(32,026)
Change in estimate[1]	**32,304**	179,000
Balance, end of year	**488,901**	497,982
Expected to be incurred within one year	**18,559**	15,185
Expected to be incurred beyond one year	**470,342**	482,797

(1) Relates to changes in estimated costs, inflation rates, discount rates and anticipated settlement dates of decommissioning liabilities.

13. Deferred 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. The difference results from the following items:

($ thousands)	**Year ended December 31, 2015**	Year ended December 31, 2014
Income (loss) before taxes	**(955,596)**	39,170
Current statutory income tax rate	**26.0%**	25.1%
Income tax expense (recovery) at current statutory rate	**(248,455)**	9,832
Non-deductible portion of unrealized foreign exchange	**27,787**	17,191
Non-deductible share-based compensation	**4,271**	3,860
Goodwill impairment	**—**	2,812
Effect of tax rate changes and rate variance	**11,281**	(283)
Other	**1,065**	911
Deferred income taxes (recovery)	**(204,051)**	34,323

The tax rate consists of the combined federal and provincial statutory tax rates for Bonavista for the years ended December 31, 2015 and December 31, 2014. The Alberta tax rate increased from 10% to 12% effective July 1, 2015 resulting in a $19.0 million reduction in the income tax recovery. The Corporation expects its taxable temporary differences to reverse at 26.95% as compared to the current statutory rate of 26.0%.

	Year ended December 31, 2015	Year ended December 31, 2014
($ thousands)		
Deferred income tax liabilities:		
Capital assets in excess of tax value	**289,927**	446,249
Financial instrument contracts	**21,696**	38,561
Debt issue costs	**1,151**	1,342
Deferred income tax assets:		
Decommissioning liabilities	**(131,759)**	(124,794)
Non-capital losses	**(109,515)**	(83,295)
Other liability	**(3,345)**	(3,471)
Issue costs	**(2,499)**	(4,094)
Share-based compensation	**(442)**	(1,233)
Deferred income taxes	**65,214**	269,265

A continuity of the net deferred income tax liability is detailed in the following tables:

	Balance December 31, 2013 (Asset)/Liability	Recognized in profit and loss (Asset)/Liability	Recognized in equity Asset	Acquired in business combinations (Asset)/Liability	Balance December 31, 2014 (Asset)/Liability
($ thousands)					
Property, plant and equipment	463,502	(17,419)	—	166	446,249
Decommissioning liabilities	(101,988)	(22,640)	—	(166)	(124,794)
Non-capital losses	(105,993)	22,698	—	—	(83,295)
Issue costs	(4,465)	2,475	(2,104)	—	(4,094)
Other liability	(3,786)	315	—	—	(3,471)
Foreign exchange	(2,151)	2,151	—	—	—
Debt issue costs	1,455	(113)	—	—	1,342
Financial instrument contracts	(8,764)	47,325	—	—	38,561
Share-based compensation	(616)	(469)	(148)	—	(1,233)
	237,194	34,323	(2,252)	—	269,265

	Balance December 31, 2014 (Asset)/Liability	Recognized in profit and loss (Asset)/Liability	Recognized in equity (Asset)/Liability	Acquired in business combinations (Asset)/Liability	**Balance December 31, 2015 (Asset)/Liability**
($ thousands)					
Property, plant and equipment	446,249	**(156,322)**	**—**	**—**	**289,927**
Decommissioning liabilities	(124,794)	**(6,965)**	**—**	**—**	**(131,759)**
Non-capital losses	(83,295)	**(26,220)**	**—**	**—**	**(109,515)**
Issue costs	(4,094)	**1,595**	**—**	**—**	**(2,499)**
Other liability	(3,471)	**126**	**—**	**—**	**(3,345)**
Debt issue costs	1,342	**(191)**	**—**	**—**	**1,151**
Financial instrument contracts	38,561	**(16,865)**	**—**	**—**	**21,696**
Share-based compensation	(1,233)	**791**	**—**	**—**	**(442)**
	269,265	**(204,051)**	**—**	**—**	**65,214**

The following is a summary of the estimated tax pools:

	December 31, 2015	December 31, 2014
($ thousands)		
Canadian oil and gas property expense	**724,273**	817,360
Canadian development expense	**715,497**	802,495
Canadian exploration expense	**313,758**	295,302
Undepreciated capital cost	**437,363**	417,556
Non-capital losses	**406,362**	332,384
Other	**9,273**	16,337
Total	**2,606,526**	2,681,434

Non-capital losses carry forward of $406.4 million (December 31, 2014 - $332.4 million) expire in the years 2028 through 2035. Bonavista has capital losses of $47.9 million (December 31, 2014 - $48.7 million) available for carry forward against future capital gains indefinitely that is not included in the deferred income tax asset. For the years ended December 31, 2015 and 2014 Bonavista paid no tax installments.

14. Commitments

The following table details Bonavista's contractual obligations for long-term debt, lease obligations and other purchase and capital commitments as at December 31, 2015

	Total	2016	2017	2018	2019	2020 and thereafter
($ thousands)						
Long-term debt repayments(1)(3)	1,265,632	34,600	159,160	—	272,056	799,816
Interest payments(2)(3)	227,658	40,127	37,698	33,046	33,046	83,741
Office lease(4)	29,195	6,068	6,068	6,356	6,760	3,943
Drilling and completions capital(5)	12,351	12,351	—	—	—	—
Drilling service contracts(6)	6,436	2,342	2,342	1,752	—	—
Transportation expenses	84,957	25,872	24,396	16,278	10,587	7,824
Total contractual obligations	**1,626,229**	**121,360**	**229,664**	**57,432**	**322,449**	**895,324**

(1) Long-term debt repayments include the bank loan facility and principal payments due on senior unsecured notes. Based on the existing terms of the revolving bank credit facility, the amounts owing under this facility are required to be paid on September 10, 2019.
(2) Fixed interest payments on senior unsecured notes.
(3) US dollars payments are converted using the exchange rate $1.384 CDN$/US$ dollar.
(4) Office lease expires July 31, 2020.
(5) The drilling and completions capital commitment is on fee lands of a partner in Bonavista's West Central Core area, the remaining commitment is to be fulfilled by the end of 2016.
(6) The drilling service contracts are with one service provider extending over a three year term.

15. Supplemental disclosure

a. Income statement presentation

Bonavista's consolidated statements of income (loss) and comprehensive income (loss) are prepared primarily by the nature of expense, with the exception of employee compensation costs which are included in both the operating and general and administrative expense line items. The following table details the amount of total employee compensation costs included in the operating and general and administrative expense line items in the consolidated statements of income (loss) and comprehensive income (loss).

($ thousands)	**Year ended December 31, 2015**	Year ended December 31, 2014
Operating	**13,529**	12,832
General and administrative	**31,568**	34,221
Total employee compensation costs	**45,097**	47,053

b. Compensation of key management personnel

Bonavista has determined that its key management personnel includes both officers and directors. Short-term benefits are comprised of salaries and directors fees, annual bonuses and other benefits. In addition, share-based compensation provided to key management personnel includes awards offered under Bonavista's long-term incentive plans. The following table details remuneration to key management personnel included in general and administrative expenses on the consolidated statements of income (loss) and comprehensive income (loss).

($ thousands)	**Year ended December 31, 2015**	Year ended December 31, 2014
Short-term benefits	**3,222**	3,756
Share-based payments	**3,551**	6,830
	6,773	10,586

CORPORATE INFORMATION

DIRECTORS

Keith A. MacPhail, *(2)(5)*
Executive Chairman

Jason E. Skehar, *(5)*
President and CEO

Ian S. Brown *(1)(4)*

Michael M. Kanovsky *(1)(2)(4)(5)*

Sue Lee *(3)(4)*

Margaret A. McKenzie *(1)(3)*

Robert G. Phillips *(4)*

Ronald J. Poelzer *(5)*

Christopher P. Slubicki *(2)(3)*

(1) Member of the Audit Committee

(2) Member of the Reserves Committee

(3) Member of the Compensation Committee

(4) Member of the Governance and Nominating Committee

(5) Member of the Executive Committee

OFFICERS

Keith A. MacPhail,
Executive Chairman

Jason E. Skehar,
President and Chief Executive Officer

Bruce W. Jensen,
Chief Operating Officer

Dean M. Kobelka,
Vice President, Finance and Chief Financial Officer

Magni Lake,
Vice President, Marketing

Wayne E. Merkel,
Vice President, Exploration

Colin J. Ranger,
Vice President, Production

Lynda J. Robinson,
Vice President, Human Resources and Administration

Scott W. Shimek,
Vice President, Operations

Cory J. Stewart,
Vice President, Land

Scott L. Wilhelm,
Vice President, Engineering

Grant A. Zawalsky,
Corporate Secretary

AUDITORS

KPMG LLP
Chartered Professional Accountants
Calgary, Alberta

BANKERS

Canadian Imperial Bank of Commerce
The Toronto-Dominion Bank
Bank of Montreal
Royal Bank of Canada
The Bank of Nova Scotia
National Bank of Canada
Alberta Treasury Branches
Caisse Centrale Desjardins
Citibank, N.A. (Canadian Branch)
Sumitomo Mitsui Banking Corporation of Canada
Union Bank of California, N.A. (Canada Branch)
Calgary, Alberta

ENGINEERING CONSULTANTS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
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REGISTRAR AND TRANSFER AGENT

Valiant Trust Company
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BONAVISTA
ENERGY CORPORATION