BONAVISTA ENERGY CORPORATION

ANNUAL REPORT 2016

March 2, 2017

Highlights

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% Change	**2016**	2015	% Change
Financial						
($ thousands, except per share)						
Production revenues	**141,842**	137,260	3 %	**445,434**	599,999	(26)%
Funds from operations[(1)]	**78,742**	95,792	(18)%	**264,391**	385,351	(31)%
Per share[(1) (2)]	**0.31**	0.44	(30)%	**1.11**	1.77	(37)%
Dividends declared	**2,493**	11,664	(79)%	**13,891**	76,762	(82)%
Per share	**0.01**	0.055	(82)%	**0.06**	0.37	(84)%
Net loss	**(12,021)**	(454,616)	97 %	**(95,998)**	(751,545)	87 %
Per share[(3)]	**(0.05)**	(2.09)	98 %	**(0.40)**	(3.45)	88 %
Adjusted net income (loss)[(4)]	**60,855**	(443,793)	114 %	**22,259**	(696,634)	103 %
Per share[(3)]	**0.24**	(2.04)	112 %	**0.09**	(3.20)	103 %
Total assets				**3,172,157**	3,523,716	(10)%
Long-term debt, net of working capital				**946,935**	1,265,820	(25)%
Long-term debt, net of adjusted working capital[(5)]				**877,523**	1,310,663	(33)%
Shareholders' equity				**1,560,244**	1,548,266	1 %
Capital expenditures:						
Exploration and development	**58,574**	56,084	4 %	**153,871**	313,905	(51)%
Dispositions, net of acquisitions	**(117,666)**	(5,540)	2,024 %	**(167,905)**	(30,552)	450 %
Weighted average outstanding equivalent shares: (thousands)[(3)]						
Basic	**253,906**	218,010	16 %	**237,806**	217,660	9 %
Diluted	**258,729**	220,924	17 %	**242,106**	220,117	10 %
Operating						
(boe conversion – 6:1 basis)						
Production:						
Natural gas (mmcf/day)	**278**	325	(14)%	**280**	337	(17)%
Natural gas liquids (bbls/day)	**19,941**	20,804	(4)%	**18,247**	17,666	3 %
Oil (bbls/day)[(6)]	**3,069**	4,934	(38)%	**3,708**	5,445	(32)%
Total oil equivalent (boe/day)	**69,339**	79,862	(13)%	**68,550**	79,288	(14)%
Product prices:[(7)]						
Natural gas ($/mcf)	**3.31**	3.44	(4)%	**3.13**	3.56	(12)%
Natural gas liquids ($/bbl)	**25.83**	19.39	33 %	**19.97**	23.17	(14)%
Oil ($/bbl)[(6)]	**68.80**	86.61	(21)%	**61.89**	81.23	(24)%
Total oil equivalent ($/boe)	**23.75**	24.39	(3)%	**21.41**	25.88	(17)%
Operating expenses ($/boe)	**5.75**	5.85	(2)%	**5.60**	6.60	(15)%
General and administrative expenses ($/boe)	**1.09**	0.97	12 %	**1.08**	1.12	(4)%
Cash costs ($/boe)[(8)]	**9.40**	9.80	(4)%	**9.40**	10.70	(12)%
Operating netback ($/boe)[(9)]	**15.14**	15.76	(4)%	**13.44**	16.16	(17)%

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

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

(5) Amounts have been adjusted to exclude associated assets or liabilities from financial instrument commodity contracts and decommissioning liabilities. Also referenced as Total net debt.

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

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

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

(9) Operating netback as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculations of similar measures for other entities. Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, operating and transportation expenses calculated on a per boe basis.

Highlights (cont'd)			
Years ended December 31	**2016**	2015	% Change
Drilling:			
Gross	**46**	78	(41)%
Net	**43.1**	70.1	(39)%
Land (net acres):			
Undeveloped	**568,051**	705,610	(19)%
Total	**1,754,634**	1,929,041	(9)%
Reserves:(10)			
Proved producing:			
Natural gas (bcf)(11)	**632.3**	614.9	3 %
Oil and natural gas liquids (mbbls)(12)	**50,517**	59,592	(15)%
Total oil equivalent (mboe)	**155,907**	162,072	(4)%
Total proved:			
Natural gas (bcf)(11)	**1,128.1**	1,026.0	10 %
Oil and natural gas liquids (mbbls)(12)	**85,159**	91,230	(7)%
Total oil equivalent (mboe)	**273,183**	262,224	4 %
Proved plus probable:			
Natural gas (bcf)(11)	**1,721.0**	1,601.7	7 %
Oil and natural gas liquids (mbbls)(12)	**127,366**	139,543	(9)%
Total oil equivalent (mboe)	**414,205**	406,494	2 %
% Proved producing	**38%**	40%	(2)%
% Proved	**66%**	65%	1 %
% Probable	**34%**	35%	(1)%
Net present value of future cash flow before income taxes ($ millions, proved plus probable):			
0% discount rate	**6,050**	5,568	9 %
5% discount rate	**3,876**	3,492	11 %
10% discount rate	**2,748**	2,412	14 %
15% discount rate	**2,092**	1,788	17 %
Reserve life index (years):(13)			
Total proved	**10.5**	9.7	8 %
Proved plus probable	**14.4**	14.1	2 %
Reserves (boe per thousand shares - basic)(3):			
Total proved	**1,149**	1,200	(4)%
Proved plus probable	**1,742**	1,860	(6)%
Finding and development costs - proved plus probable ($/boe)(14)	**6.97**	7.26	(4)%
Recycle ratio - proved plus probable(15)	**1.9**	2.2	(14)%
Finding, development and acquisition costs - proved plus probable ($/boe)(14)	**(0.55)**	9.84	(106)%
Recycle ratio - proved plus probable(15)	**(24.4)**	1.6	(1,625)%

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

	Three months ended			
Share Trading Statistics	**December 31, 2016**	**September 30, 2016**	**June 30, 2016**	**March 31, 2016**
($ per share, except volume)				
High	5.58	4.60	3.77	3.28
Low	3.95	3.15	2.23	0.94
Close	4.81	4.22	3.30	2.62
Average Daily Volume - Shares	877,141	1,135,181	1,492,555	1,317,618

MESSAGE TO SHAREHOLDERS

Bonavista entered 2017 in a remarkably stronger position relative to a year ago. The fragile commodity price environment in 2016 challenged the reinvestment economics of most oil and natural gas assets in North America. For Bonavista, we took the opportunity in this environment to strengthen our financial position, further concentrate the asset base, and reveal the exceptional capital and operating efficiencies of our portfolio that validate the sustainability of our business. We have reduced our total net debt by $433 million while we upgraded the performance and the potential of our asset portfolio to purposefully transition from defense to offense in 2017.

Today, we are positioned with two strategic core areas, each serving a different but invaluable purpose as we create shareholder value. First, our Deep Basin core area, characterized by stacked, resource-rich natural gas reservoirs, will experience 40% growth in production in 2017 while delivering top-decile operating margins with approximately 90% of our production being processed at our facilities. Second, our West Central core area, with over twenty years of predictable and reliable development inventory, will generate significant excess net operating income to fund our growth in the Deep Basin and to strengthen our financial position.

Overall, the flexibility created by generating surplus funds from operations provides us with several options in this environment. Accordingly, we intend to grow production between seven and 10%, and funds from operations between 10% to 20%, all while spending 90% to 100% of funds flow this year. This internally funded organic growth will result in forecasted debt to funds from operations of 2.5 times at year-end 2017.

Operational and financial accomplishments for 2016 include:

- Reduced our corporate total net debt by $433 million or 33%;
- Production for the fourth quarter averaged 69,339 boe per day, an 8% increase over third quarter production. Current production is 71,000 boe per day, notwithstanding the delay of completion operations on certain wells drilled in the fourth quarter of 2016 and first quarter of 2017;
- Underspent our exploration and development ("E&D") budget resulting in a net capital credit of $14.0 million with proceeds from our acquisitions and divestitures ("A&D") program exceeding capital expenditures from our E&D program for 2016;
- Reduced 2016 operating costs to $5.60 per boe and cash costs to $9.40 per boe, representing improvements of 15% and 12% respectively, when compared to 2015;
- Replaced 131% of 2016 production with the addition of 32.8 MMboe of proved plus probable reserves at no net cost;
- Added 30.8 MMboe of proved plus probable reserves replacing 123% of 2016 production with an E&D capital spending program of $153.9 million, being 58% of funds from operations generated in the year;
- Divested of approximately 5,000 boe per day of non-core assets resulting in a 14% reduction of inactive well count and $75 million of decommissioning liability;
- Maintained entrance to exit production at approximately 70,000 boe per day, notwithstanding a 51% reduction in E&D capital spending;
- Secured firm transportation on the Nova Gas Transmission Ltd. ("NGTL") system north of the James River receipt point ("restricted area") equal to 116% of our 2017 forecasted natural gas sales in this area; and

- Prudently protected 2017 funds from operations with a commodity hedge portfolio resulting in:
    - 70% of our forecasted 2017 natural gas production hedged at an AECO price of $3.32 per mcf;
    - 75% of oil and condensate volumes hedged at CDN$67.17 per bbl WTI; and
    - 49% of our propane volumes hedged at CDN$28.37 per bbl.

2016 YEAR-TO-DATE CORE AREA HIGHLIGHTS

DEEP BASIN CORE AREA

The Deep Basin is clearly our vehicle for growth as we create shareholder value in 2017. In 2016, we increased our land position by 24% to 365,000 net acres and currently have approximately 550 horizontal drilling locations in this core area. Our Deep Basin is characterized by stacked, resource-rich natural gas reservoirs with low cost, high margin operations. We support our production base and development plans with 225 mmcf per day of operated processing capacity with plans to expand this capacity to 265 mmcf per day by the end of the first quarter. Egress certainty has been established with firm transportation secured on the NGTL system equal to 116% of our forecasted natural gas sales for 2017 in the area.

In 2016, we spent $75 million on E&D activities drilling 18 (17.4 net) horizontal wells supporting production rates averaging 19,273 boe per day or 28% of corporate production.

In 2017, we will increase drilling activity by 67% to 30 (26.4 net) wells growing production 40% to average 27,000 boe per day. We are currently producing approximately 25,000 boe per day in the Deep Basin.

Spirit River (Wilrich, Falher, Notikewin) Natural Gas

We drilled 13 (13.0 net) horizontal wells in 2016 including eight (8.0 net) wells in the fourth quarter, one of which was drilled to delineate the southern boundaries of our Ansell block. Six of these wells are currently on-stream and are performing similar to our first quarter 2016 program. Pressure pumping service availability delayed the start of completion operations for the last two wells of 2016 and our first quarter 2017 wells until the end of February. Two of these wells were completed recently and are our first extended reach wells drilled at Ansell in a NW-SE orientation. This two well pad has been on test for three days, and is currently being tested in-line at a combined rate of 35 mmcf per day, meaningfully outperforming our expectations. We have six wells currently drilled at Ansell and in the cue for completion before spring break-up.

Our Ansell facility will be expanded from 60 mmcf per day to 100 mmcf per day within the next month for a capital cost of approximately $8 million. Additionally, we have egress certainty with firm service commitments on the TransCanada pipeline equal to 116% of our forecasted 2017 production in this area, and optionality with a connection to the Alliance pipeline. Furthermore, we continue to expand our presence in the area and have acquired land to accommodate 6.5 net extended reach drilling locations.

Operating costs were $2.50 per boe in 2016, a 33% reduction relative to 2015. Capital efficiencies have also improved in 2016 by 35% to $10,200 per boe per day and proved plus probable finding and development costs were reduced by five percent to $6.55 per boe. Economics remain strong at Ansell where drilling and completion costs have continued to improve, our wells drilled year-to-date in 2017 have an average cost of $4.1 million, seven percent below our budget and an improvement from our 2016 program.

Our 2017 Wilrich program of 21 (20.8 net) wells, the majority of which are extended reach, will support production growth of approximately 69% to 16,300 boe per day from the fourth quarter of 2016 as compared to the same period in 2017.

In addition to our Ansell Wilrich program, we plan to drill three (2.0 net) Notikewin and Falher channel wells, including two extended reach horizontal wells. Numerous successful wells have been drilled by the industry offsetting our land base. As we delineate these additional zones, we expect to add future value, as no reserves have been currently booked on these locations.

Bluesky Natural Gas

We drilled three (2.9 net) horizontal Bluesky wells on our Pine Creek acreage in 2016 including one (1.0 net) in the fourth quarter. Our 2016 Bluesky program is performing to our expectations supporting fourth quarter 2016 production of 4,100 boe per day, 34% growth relative to the same period last year.

The Bluesky at Pine Creek is rich in natural gas liquids with 50% of its natural gas liquids ("NGL") component being condensate. We plan to drill three (2.3 net) horizontal wells in 2017, including our first extended reach horizontal well, and will focus on acreage acquired in the recent asset exchange.

WEST CENTRAL CORE AREA

Our West Central core area is a reliable production base that is capable of generating significant excess funds from operations for many years to come. The area draws its strength from a low decline, optimized capital cost structure, year round access, resilient economics and predictable well results. With approximately 740,000 net acres and a drilling inventory of approximately 730 horizontal locations (more than 20 years of development), this core area offers predictable low risk development that will undeniably maintain production for many years as the area serves as a source of funding to enhance growth in the Deep Basin. We have built an extensive network of infrastructure to support our continued development of this core area, including over 2,200 kilometers of pipelines in service and 33 facilities, the majority of which are operated by Bonavista.

In 2016, we spent $71.2 million on E&D activities, which included drilling 28 (25.7 net) horizontal wells, supporting production rates averaging 44,236 boe per day or 65% of corporate production. In 2017, we plan to drill 33 (31.7 net) wells, with E&D spending of $133.9 million inclusive of incremental infrastructure spending. Our development is focused on Willesden Green, Strachan and Morningside, where we anticipate longer average horizontal lengths. This capital program maintains production between 43,000 and 44,000 boe per day while consuming only 56% of net operating income generated in this core area. Fortunately, with robust NGL production and the recent recovery in NGL prices, this core area will produce a notable $110 million of excess net operating income in 2017.

Glauconite Natural Gas

We drilled 22 (19.7 net) horizontal wells in 2016 including five (4.3 net) in the fourth quarter resulting in average 2016 production of 22,800 boe per day.

Our efficient operating structure continued to improve throughout 2016. Drilling and completion costs improved in the fourth quarter averaging $1.9 million, a 27% improvement relative to the same prior year period. We anticipate production efficiencies of between $8,000 and $10,000 per boepd in 2017.

Development economics have strengthened in the Glauconite resulting from improved NGL pricing. In 2017, the composite NGL barrel in the Glauconite is forecasted to generate revenue of $26.80 per barrel, a 45% increase over 2016.

Late in the fourth quarter of 2016, we completed the production redirects associated with the assets acquired through the asset exchange. This consolidation has enhanced our efficiencies by doubling liquid recoveries and reducing operating costs by approximately 50%. These improvements are anticipated to be captured in the first quarter of 2017.

We will continue to develop our Strachan area in 2017 by drilling four (3.95 net) wells out of our total 2017 Glauconite program. Continued success will provide an opportunity to create a long-term infrastructure solution in 2018 that will significantly enhance development economics.

We have drilled over 320 horizontal wells in the Glauconite and have another 350 drilling locations in inventory. The predictable, reliable nature of this development, coupled with its resilient economics continues to provide a dependable source of funds flow in 2017. We anticipate drilling 16 (15.7 net) wells in 2017.

Spirit River Falher Natural Gas

We drilled six (6.0 net) horizontal wells in 2016 at Morningside including one (1.0 net) in the fourth quarter. Our 2016 program successfully extended the boundaries of the play and we intend on delineating three new channels in 2017. In the fourth quarter of 2016, we closed a small acquisition adding 50 boe per day of production and four sections prospective for Falher development.

Capital cost reductions continue to improve our capital efficiencies, with our fourth quarter drilling and completion costs improving 20% to $1.6 million as compared to the prior year quarter.

The economics of our Morningside Falher play are impressive, with a forecasted 2017 internal rate of return ("IRR") of 73% and a payout of 1.4 years, it remains competitive with the top plays in western Canada. As such, we are increasing our drilling activity by 150% in 2017 to 15 (14.5 net) wells and expect this development to deliver production growth in excess of 100% to approximately 7,000 boe per day from the fourth quarter of 2016 to the same period in 2017.

STRENGTHS OF BONAVISTA ENERGY CORPORATION

2017 marks our 20th year of operations. Throughout this period, 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.

Our production and development activity is largely concentrated in two core areas in Alberta, which together represent approximately 95% of current production. We create opportunities through undeveloped land purchases, asset swaps, asset acquisitions and farm-in opportunities in these areas. Specifically over the past five years, advanced 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 asset base ensures operating margins that compete favorably in most operating environments. Furthermore, our assets are predominantly operated by us, ensuring a sustainable pace of operations and a direct influence over our operating and capital cost efficiencies. In 2016, our E&D program consumed only 58% of our funds from operations to replace 123% of 2016 production with proved plus probable reserves. We also achieved a 15% improvement in operating costs and a 23% improvement in our cost to add production relative to 2015.

Our team brings a successful track record of executing reliable development programs with consistency and precision. We continually strive for financial 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 nine percent of the equity of Bonavista, aligning our interests with those of our external shareholders.

OUTLOOK

The fundamentals of our industry have improved throughout the second half of 2016 creating a more favourable economic investment environment. As a result, the industry including Bonavista will deploy incremental capital in 2017.

Undoubtedly, as commodity supply and demand seek equilibrium, pricing will remain volatile in 2017 and accordingly, for 2017, we have hedged approximately 70% of our natural gas, 75% of our crude oil and condensate, and 49% of our propane in excess of current forward pricing on average. Should we experience another tumultuous year of natural gas pricing whereby reinvestment economics become challenged, our strong hedge portfolio will enable us to maintain production at a minimum of 70,000 boe per day for 2017 at natural gas prices as low as $1.50 per gj at AECO and generate between $120 and $125 million of excess funds from operations to enhance financial flexibility.

Similarly, service cost inflation resulting from recently increased activity levels in western Canada will likely affect the availability of the service and could affect our profitability in 2017. Our capital and operating efficiencies have improved significantly throughout 2016 with numerous initiatives completed near the end of last year. This will serve as an opposing force to cost inflation preparing the foundation for continued capital efficient operations in 2017.

Lastly, concerns with access to the NGTL infrastructure has been topical as of late. With firm NGTL transportation contracts representing approximately 116% of our forecasted natural gas production in the constrained areas, we are confident we can deliver on our growth aspirations in 2017.

We will remain aware and agile with our development plans but clearly have taken numerous steps to strengthen our position in this environment. With constructive reinvestment economics still at play, we remain committed to continually enhancing the performance of our program to support our average daily production forecast of between 73,500 and 75,500 boe per day in 2017. This will be achieved through a disciplined and sustainable capital program of between $280 and $300 million drilling 55 to 65 net wells, resulting in seven to 10 percent production growth within funds flow from operations.

We thank our employees for their commitment and dedication, our Board of Directors for their guidance and our shareholders for their long-term support. We look forward to delivering profitable per share growth while creating additional financial flexibility in 2017.

On behalf of the Board of Directors

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

March 2, 2017
Calgary, Alberta

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is dated March 2, 2017 and should be read in conjunction with the audited consolidated financial statements (the "financial statements") for the year ended December 31, 2016, together with notes related thereto, for a full understanding of the financial position and results of operations of Bonavista Energy Corporation's ("Bonavista" or the "Corporation"). Additional information relating to Bonavista, including the Corporation's Annual Information Form, is available on SEDAR at www.sedar.com *or can be obtained from Bonavista's website at* www.bonavistaenergy.com.

The audited consolidated financial statements and comparative information for the year ended December 31, 2016 have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standard Board ("IASB"). The MD&A contains Non-GAAP measures and forward looking information. The MD&A should be read in conjunction with Bonavista's disclosures under the heading "Non-GAAP Measures", "Other Management Performance Measures" and "Forward-looking Statements", included at the end of the MD&A.

Operations - Bonavista's exploration and development program of $153.9 million led to the drilling of 28 (25.7 net) wells in the West Central core area and 18 (17.4 net) wells in the Deep Basin core area for the year ended December 31, 2016. Consistent with Bonavista's asset concentration strategy, exploration and development activities for the year were focused on the development of Bonavista's core areas. The wells drilled in the West Central core area included 22 (19.7 net) Glauconite wells and six (6.0 net) Spirit River wells. The wells drilled in the Deep Basin core area included 14 (14.0 net) Spirit River wells, three (2.9 net) Bluesky wells and one (0.5 net) Cardium well.

While Bonavista's exploration and development program was curtailed throughout 2016 in response to challenging commodity prices, Bonavista remained focused on strengthening its financial position by reducing long-term debt. As a result, Bonavista is well positioned with greater financial flexibility and a solid foundation of quality assets to allow for future growth. Bonavista is planning to drill between 55 and 65 net wells within its core areas in 2017, with a capital budget of between $280 million and $300 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 (calculated using a discount rate of 10%), 92% were evaluated by independent third-party engineers, GLJ Petroleum Consultants Ltd. ("GLJ") in their report dated February 1, 2017. The balance of approximately 8% 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 at December 31, 2016 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	632,341	5,526	44,991	155,907
Proved Non-Producing	32,977	305	1,380	7,181
Proved Undeveloped	462,829	2,097	30,860	110,095
Total Proved	**1,128,147**	**7,928**	**77,231**	**273,183**
Probable	592,890	3,241	38,966	141,022
Proved plus Probable	**1,721,037**	**11,169**	**116,197**	**414,205**
Proved reserve life index (years)(6)				**10.5**
Proved plus Probable reserve life index (years)(6)				**14.4**

(1) Bonavista's working interest reserves are based on the GLJ reserve report dated February 1, 2017, GLJ reserve estimates based on forecast prices and costs as of January 1, 2017.
(2) Amounts may not add due to rounding.
(3) Includes Conventional Natural Gas and Coal Bed Methane.
(4) Includes Light, Medium and Heavy Crude 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. Additionally, given that the value ratio based on the current price of crude oil, as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value.
(6) Calculated based on the amount for the relevant reserve category divided by the 2017 production forecast prepared by GLJ.

Reserve Reconciliation(1)	**Proved**	**Probable**	**Proved plus Probable**
	(mboe)	(mboe)	(mboe)
Balance as at December 31, 2015	262,224	144,270	406,494
Extensions and Improved Recovery(2)	**33,503**	**11,304**	**44,808**
Technical Revisions	**(1,793)**	**(6,685)**	**(8,478)**
Acquisitions	**30,393**	**8,536**	**38,929**
Dispositions	**(21,362)**	**(15,635)**	**(36,997)**
Economic Factors	**(4,738)**	**(767)**	**(5,506)**
Production	**(25,045)**	**—**	**(25,045)**
Balance as at December 31, 2016	**273,183**	**141,022**	**414,205**

(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 2016 year end proved reserves totaled 273.2 mmboe, a 4% increase when compared to the 262.2 mmboe for the year ended 2015. Proved plus probable reserves increased 2% to 414.2 mmboe when compared to 406.5 mmboe for the year ended 2015. Bonavista's proved plus probable reserve life index increased 2% to 14.4 years for the year ended 2016 compared to 14.1 years for the year ended 2015 demonstrating the sustainable balance of Bonavista's capital program, reserve additions and production levels.

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	**2016**	2015	% Change
Reserves (mboe):			
Proved producing	**155,907**	162,072	(4)%
Total proved	**273,183**	262,224	4 %
Proved plus probable	**414,205**	406,494	2 %
Capital expenditures ($ millions):			
Exploration and development	**153.9**	313.9	(51)%
Dispositions, net of acquisitions	**(167.9)**	(30.6)	449 %
Total capital expenditures(1)	**(14.0)**	283.4	(105)%
Operating Netback ($/boe):(2)			
Current year	**13.44**	16.16	(17)%
Three-year weighted average	**17.54**	19.72	(11)%
Finding and Development Expenditures(5):			
Proved Producing:			
Change in F&D costs ($ thousands)	**(173)**	(339)	49 %
Reserves additions (mboe)	**15,831**	26,252	(40)%
F&D costs ($/boe)(3)	**9.71**	11.94	(19)%
F&D recycle ratio(4)	**1.4**	1.4	— %
F&D three-year weighted costs ($/boe)(3)	**12.04**	13.57	(11)%
F&D recycle ratio three-year weighted average(4)	**1.5**	1.5	— %
Total Proved:			
Change in F&D costs ($ thousands)	**86,377**	(188,683)	146 %
Reserves additions (mboe)	**26,972**	20,346	33 %
F&D costs ($/boe)(3)	**8.91**	6.15	45 %
F&D recycle ratio(4)	**1.5**	2.6	(42)%
F&D three-year weighted costs ($/boe)(3)	**10.40**	12.21	(15)%
F&D recycle ratio three-year weighted average(4)	**1.7**	1.6	6 %
Proved plus Probable:			
Change in F&D costs ($ thousands)	**60,902**	(183,483)	133 %
Reserves additions (mboe)	**30,824**	17,975	71 %
F&D costs ($/boe)(3)	**6.97**	7.26	(4)%
F&D recycle ratio(4)	**1.9**	2.2	(14)%
F&D three-year weighted costs ($/boe)(3)	**9.11**	10.65	(14)%
F&D recycle ratio three-year weighted average(4)	**1.9**	1.9	— %
Finding, Development and Acquisition Expenditures(5):			
Proved Producing:			
Change in FD&A costs ($ thousands)	**(2,269)**	4,667	(149)%
Reserves additions (mboe)	**18,879**	21,539	(12)%
FD&A costs ($/boe)(3)	**(0.86)**	13.37	(106)%
FD&A recycle ratio(4)	**(15.6)**	1.2	(1,400)%
FD&A three-year weighted costs ($/boe)(3)	**9.69**	13.35	(27)%
FD&A recycle ratio three-year weighted average(4)	**1.8**	1.5	20 %

Years ended December 31	**2016**	2015	% Change
Finding, Development and Acquisition Expenditures[5]:			
Total Proved:			
Change in FD&A costs ($ thousands)	**111,576**	(186,034)	160 %
Reserves additions (mboe)	**36,004**	15,388	134 %
FD&A costs ($/boe)[3]	**2.71**	6.32	(57)%
FD&A recycle ratio[4]	**5.0**	2.6	92 %
FD&A three-year weighted costs ($/boe)[3]	**7.81**	12.10	(35)%
FD&A recycle ratio three-year weighted average[4]	**2.2**	1.6	38 %
Proved plus Probable:			
Change in FD&A costs ($ thousands)	**(3,821)**	(198,572)	98 %
Reserves additions (mboe)	**32,756**	8,618	280 %
FD&A costs ($/boe)[3]	**(0.55)**	9.84	(106)%
FD&A recycle ratio[4]	**(24.4)**	1.6	(1,625)%
FD&A three-year weighted costs ($/boe)[3]	**6.42**	10.42	(38)%
FD&A recycle ratio three-year weighted average[4]	**2.7**	1.9	42 %

(1) Amounts may not add due to rounding.
(2) Operating netback as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculations of similar measures for other entities. Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, operating and transportation expenses calculated on a per boe basis.
(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 Bonavista's working interest reserves.

Bonavista demonstrated significant improvements in overall efficiencies in 2016, resulting in proved plus probable F&D cost reductions of 4% to $6.97 per boe from $7.26 per boe in 2015. Bonavista considers its recycle ratio to be an important measure of profitability, delivering a F&D recycle ratio of 1.9:1 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,		
	2016	2015	% Change	**2016**	2015	% Change
($ thousands, except per boe and share amounts where noted)						
Production:						
Natural gas (mmcf/d)	**278**	325	(14)%	**280**	337	(17)%
Natural gas liquids (bbls/d)	**19,941**	20,804	(4)%	**18,247**	17,666	3 %
Oil (bbls/day)[1]	**3,069**	4,934	(38)%	**3,708**	5,445	(32)%
Total production (boe/d)	**69,339**	79,862	(13)%	**68,550**	79,288	(14)%
Product prices[2]:						
Natural gas ($/mmcf)	**3.31**	3.44	(4)%	**3.13**	3.56	(12)%
Natural gas liquids ($/bbl)	**25.83**	19.39	33 %	**19.97**	23.17	(14)%
Oil ($/bbl)	**68.80**	86.61	(21)%	**61.89**	81.23	(24)%
Production revenues	**141,842**	137,260	3 %	**445,434**	599,999	(26)%
per boe	**22.24**	18.68	19 %	**17.75**	20.73	(14)%
Production revenues and realized gains on financial instrument commodity contracts	**151,525**	179,184	(15)%	**537,206**	749,152	(28)%
per boe	**23.75**	24.39	(3)%	**21.41**	25.89	(17)%
Royalties	**12,767**	11,389	12 %	**36,903**	54,201	(32)%
per boe	**2.00**	1.55	29 %	**1.47**	1.87	(21)%
% of Production revenues	**9.0%**	8.3%	1 %	**8.3%**	9.0%	(1)%

	Three months ended December 31,			Years ended December 31,		
	2016	2015	% Change	**2016**	2015	% Change
($ thousands, except per boe and share amounts where noted)						
Operating expenses	**36,700**	43,000	(15)%	**140,592**	190,889	(26)%
per boe	**5.75**	5.85	(2)%	**5.60**	6.60	(15)%
Transportation expenses	**5,512**	9,023	(39)%	**22,566**	36,500	(38)%
per boe	**0.86**	1.23	(30)%	**0.90**	1.26	(29)%
General and administrative expenses	**6,948**	7,120	(2)%	**27,138**	32,495	(16)%
per boe	**1.09**	0.97	12 %	**1.08**	1.12	(4)%
Share-based compensation expenses	**2,058**	4,057	(49)%	**8,994**	17,157	(48)%
per boe	**0.32**	0.55	(42)%	**0.36**	0.59	(39)%
Depreciation, depletion, amortization and impairment	**64,313**	649,232	(90)%	**319,845**	1,168,016	(73)%
per boe	**10.08**	88.36	(89)%	**12.75**	40.36	(68)%
Net finance costs[3]	**26,878**	42,099	(36)%	**44,257**	166,600	(73)%
per boe	**4.21**	5.73	(27)%	**1.76**	5.76	(69)%
Interest expense	**10,856**	12,860	(16)%	**45,616**	49,716	(8)%
per boe	**1.70**	1.75	(3)%	**1.82**	1.72	6 %
Deferred income taxes (recovery)	**748**	(155,253)	100 %	**(38,929)**	(204,051)	81 %
per boe	**0.12**	(21.13)	101 %	**(1.55)**	(7.05)	78 %
Net loss	**(12,021)**	(454,616)	97 %	**(95,998)**	(751,545)	87 %
per boe	**(1.88)**	(61.88)	97 %	**(3.83)**	(25.97)	85 %
per share - basic	**(0.05)**	(2.09)	98 %	**(0.40)**	(3.45)	88 %
Dividends declared	**2,493**	11,664	(79)%	**13,891**	76,762	(82)%
per share	**0.01**	0.055	(82)%	**0.06**	0.37	(84)%
Funds from operations	**78,742**	95,792	(18)%	**264,391**	385,351	(31)%
per boe	**12.34**	13.04	(5)%	**10.54**	13.32	(21)%
per share - basic	**0.31**	0.44	(30)%	**1.11**	1.77	(37)%

(1) Oil includes light, medium and heavy oil.
(2) Product prices include realized gains and losses on financial instrument commodity contracts.
(3) Includes interest expense

Production - Production volumes for the year ended December 31, 2016 averaged 68,550 boe per day, a 14% decrease compared to an average of 79,288 boe per day in the same period of 2015. The decrease in production volumes was largely due to the disposition of non-core assets in the second half of 2015 and throughout 2016, the shut-in of low margin wells and reduced capital spending throughout 2015 and 2016 in response to low commodity prices.

For the year ended December 31, 2016, natural gas production averaged 280 mmcf per day, a 17% decrease compared to an average of 337 mmcf per day for the year ended December 31, 2015. Natural gas liquids production was 18,247 bbls per day for the year ended December 31, 2016, a 3% increase when compared to 17,666 bbls per day for the same period of 2015. The increase in natural gas liquids production and decrease in natural gas production on a percentage basis can be attributed to the significant enhancement of natural gas liquids yields as a result of a third-party plant expansion commissioned in the third quarter of 2015 and the disposition of dry natural gas weighted non-core assets in the second half of 2015 and throughout 2016. Oil production decreased 32% to 3,708 bbls per day for the year ended December 31, 2016 from 5,445 bbls per day in the same period of 2015 as a result of non-core light-oil weighted asset dispositions and production declines as Bonavista continues to focus exploration and development activities to lower cost, liquids rich natural gas properties.

Production volumes averaged 69,339 boe per day for the fourth quarter ended December 31, 2016, an 8% increase over the third quarter of 2016, but a 13% decrease when compared to an average of 79,862 boe per day for the fourth quarter of 2015. The decrease in average production volumes over the same prior year period was due to a curtailed capital program, production declines in excess of new well production, the disposition of non-core assets and the shut-in of uneconomic properties.

For the three months ended December 31, 2016, natural gas production decreased 14% to 278 mmcf per day compared to 325 mmcf per day in the same period of 2015. Natural gas liquids production decreased 4% to 19,941 bbls per day for the three months ended December 31, 2016 from 20,804 bbls per day for the same period of 2015. While production decreased for both natural gas and natural gas liquids, the larger decrease to natural gas production on a percentage basis can be attributed to the disposition of gas-weighted non-core assets in the fourth quarter of 2015. Oil production decreased 38% to 3,069 bbls per day for the three months ended December 31, 2016 from 4,934 bbls per day for the same period of 2015 as a result of non-core asset dispositions and production declines as Bonavista continues to focus exploration and development activities to lower cost, liquids rich natural gas properties.

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,		
	2016	2015	% Change	**2016**	2015	% Change
Natural gas (mmcf/day)	**278**	325	(14)%	**280**	337	(17)%
Natural gas liquids (bbls/day)	**19,941**	20,804	(4)%	**18,247**	17,666	3 %
Oil (bbls/day)	**3,069**	4,934	(38)%	**3,708**	5,445	(32)%
Total oil equivalent (boe/day)	**69,339**	79,862	(13)%	**68,550**	79,288	(14)%

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,		
	2016	2015	% Change	**2016**	2015	% Change
West Central area (boe/day)	**44,090**	51,697	(15)%	**44,236**	48,297	(8)%
Deep Basin area (boe/day)	**21,700**	19,684	10 %	**19,273**	21,459	(10)%
Other minor areas (boe/day)	**3,549**	8,481	(58)%	**5,041**	9,532	(47)%
Total oil equivalent (boe/day)	**69,339**	79,862	(13)%	**68,550**	79,288	(14)%

Bonavista's current production is approximately 71,000 boe per day the composition of which is 71% natural gas, 26% natural gas liquids and 3% light oil.

Production revenues - North American commodity prices deteriorated significantly throughout 2015 and the first six months of 2016, with indications of modest recovery presented in the second half of 2016. Higher seasonal demand for natural gas, particularly in the US, coupled with continued production declines have tempered current market oversupply and storage levels. NYMEX and AECO benchmarks have shown encouraging strength compared to the first six months of 2016, resulting in the growth in realized natural gas production revenues compared to the first half of 2016. Supply and demand imbalances have also placed continued pressure on oil and natural gas liquids pricing throughout 2015 and 2016, with moderate recoveries and increased stability in WTI benchmark prices and natural gas liquids pricing presented in the second half of 2016.

For the year ended December 31, 2016, production revenues, excluding the impact of financial instrument commodity contracts, decreased 26% to $445.4 million compared to $600.0 million for the year ended December 31, 2015. The decrease was due to a 14% decrease in commodity prices on a per boe basis in addition to the impact of a 14% decrease in average production volumes. For the three months ended December 31, 2016, production revenues excluding the impact of financial instrument commodity contracts, increased 3% to $141.8 million, compared to $137.3 million for the same period of 2015. The increase was due to a 19% increase in commodity prices on a per boe basis, partially offset by a 13% decrease in average production volumes. The increase in commodity prices was largely due to a modest recovery in natural gas and natural gas liquids pricing as a result of stronger weather-related demand, particularly in the US. In addition, propane prices rallied in the fourth quarter of 2016 to levels not seen since the fourth quarter of 2014, as a result of increased demand, stabilized inventory levels and increased export capacity in the US.

Natural gas prices, excluding the impact of financial instrument commodity contracts, decreased 17% to $2.41 per mcf for the year ended December 31, 2016, compared to $2.89 per mcf for the same period of 2015. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, decreased 9% to $20.11 per bbl for the year ended December 31, 2016, compared to $22.09 per bbl for the same period of 2015. Oil prices, excluding the impact of financial instrument commodity contracts, decreased 8% to $47.25 per bbl for the year ended December 31, 2016, compared to $51.39 per bbl for the same period of 2015. Natural gas prices, excluding the impact of financial instrument commodity contracts, for the three months ended December 31, 2016, increased 13% to $3.03 per mcf compared to $2.68 per mcf for the same period of 2015. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, increased 40% to $26.36 per bbl for the three months ended December 31, 2016, compared to $18.79 per bbl in the same period of 2015. Oil prices, excluding the impact of financial instrument commodity contracts, increased 20% to $56.23 per bbl for the three months ended December 31, 2016, compared to $46.76 per bbl for the comparable period of 2015.

Consistent with Bonavista's objective to protect funds from operations, financial instrument commodity contracts have partially mitigated Bonavista's exposure to the weak and somewhat volatile commodity price environment experienced throughout 2015 and 2016. For the year ended December 31, 2016, a gain of $91.8 million was realized on Bonavista's financial instrument commodity contracts compared to a realized gain of $149.2 million for the year ended December 31, 2015. Similarly, for the three months ended December 31, 2016, a gain of $9.7 million was realized on Bonavista's financial instrument commodity contracts compared to a realized gain of $41.9 million for the comparable period of 2015.

For the year ended December 31, 2016, natural gas prices, including the impact of financial instrument commodity contracts, decreased 12% to $3.13 per mcf compared to $3.56 per mcf for the same period of 2015. For the year ended December 31, 2016, natural gas liquids prices, including the impact of financial instrument commodity contracts, decreased 14% to $19.97 per bbl, compared to $23.17 per bbl realized for the same period of 2015. Oil prices, including the impact of financial instrument commodity contracts, decreased 24% to $61.89 per bbl for the year of 2016, when compared to $81.23 per bbl realized for the comparable period of 2015. Natural gas prices, including the impact of financial instrument contracts, for the three months ended December 31, 2016, decreased 4% to $3.31 per mcf compared to $3.44 per mcf for the same period of 2015. For the three months ended December 31, 2016, natural gas liquids prices, including the impact of financial instrument commodity contracts, increased 33% to $25.83 per bbl, from $19.39 per bbl realized for the comparable period of 2015. Oil prices, including the impact of financial instrument commodity contracts, for the fourth quarter of 2016 were $68.80 per bbl, a 21% decrease when compared to $86.61 per bbl realized for the same period of 2015.

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,	
	2016	2015	**2016**	2015
Natural gas ($/mcf):				
Production revenues	**3.03**	2.68	**2.41**	2.89
Realized gains on financial instrument commodity contracts	**0.28**	0.76	**0.72**	0.67
Realized price including financial instrument commodity contracts	**3.31**	3.44	**3.13**	3.56
Natural gas liquids ($/bbl):				
Production revenues	**26.36**	18.79	**20.11**	22.09
Realized gains (losses) on financial instrument commodity contracts	**(0.53)**	0.60	**(0.14)**	1.08
Realized price including financial instrument commodity contracts	**25.83**	19.39	**19.97**	23.17
Oil ($/bbl):				
Production revenues	**56.23**	46.76	**47.25**	51.39
Realized gains on financial instrument commodity contracts	**12.57**	39.85	**14.64**	29.84
Realized price including financial instrument commodity contracts	**68.80**	86.61	**61.89**	81.23
Total ($/boe):				
Production revenues	**22.24**	18.68	**17.75**	20.73
Realized gains on financial instrument commodity contracts	**1.51**	5.71	**3.66**	5.15
Realized price including financial instrument commodity contracts	**23.75**	24.39	**21.41**	25.88

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 net 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, natural gas and natural gas liquids 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.

At December 31, 2016, Bonavista had entered into the following costless collars to sell oil and natural gas:

Volume		**Average Price**	**Term**
Natural gas contracts			
25,000	gjs/d	CDN $3.30 - CDN $3.66 - AECO	January 1, 2017 - December 31, 2017
20,000	gjs/d	CDN $2.60 - CDN $3.00 - AECO	January 1, 2017 - December 31, 2018
5,000	gjs/d	CDN $2.90 - CDN $3.10 - AECO	November 1, 2017 - March 31, 2018
5,000	gjs/d	CDN $2.90 - CDN $3.10 - AECO	November 1, 2018 - March 31, 2019
Oil contracts			
500	bbls/d	CDN $56.00 - $64.25 - WTI	January 1, 2017 - December 31, 2017
500	bbls/d	CDN $57.00 - $65.00 - WTI	July 1, 2017 - December 31, 2017

At December 31, 2016, Bonavista had entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
Natural gas contracts				
40,000	gjs/d	CDN $2.92	Swap - AECO	January 1, 2017 - March 31, 2017
65,000	gjs/d	CDN $3.00	Swap - AECO	January 1, 2017 - December 31, 2017
10,000	gjs/d	CDN $2.60	Swap - AECO	January 1, 2017 - December 31, 2018
50,000	gjs/d	CDN $2.93	Swap - AECO	April 1, 2017 - October 31, 2017(1)
10,000	gjs/d	CDN $3.04	Swap - AECO	October 1, 2017 - December 31, 2017
45,000	gjs/d	CDN $3.09	Swap - AECO	November 1, 2017 - March 31, 2018
40,000	gjs/d	CDN $3.05	Swap - AECO	January 1, 2018 - March 31, 2018
30,000	gjs/d	CDN $2.91	Swap - AECO	January 1, 2018 - December 31, 2018(2)
10,000	gjs/d	CDN $2.70	Swap - AECO	January 1, 2018 - December 31, 2019
5,000	gjs/d	CDN $3.05	Swap - AECO	November 1, 2018 - March 31, 2019
10,550	gjs/d	US $(0.60)	Swap - AECO Basis	January 1, 2017 - December 31, 2018
10,000	gjs/d	CDN $3.23	Sold Call - AECO	January 1, 2017 - December 31, 2017
10,550	gjs/d	US $3.50	Swap - NYMEX	January 1, 2017 - March 31, 2017
26,375	gjs/d	US $3.12	Swap - NYMEX	January 1, 2017 - December 31, 2017
10,550	gjs/d	US $3.04	Swap - NYMEX	April 1, 2017 - October 31, 2017
5,275	gjs/d	US $3.36	Swap - NYMEX	October 1, 2017 - December 31, 2017(6)
10,550	gjs/d	US $2.95	Swap - NYMEX	January 1, 2018 - December 31, 2018
Natural gas liquids contracts				
500	bbls/d	US $27.72	Swap - MTB BT	January 1, 2017 - March 31, 2017(3)
500	bbls/d	US $27.72	Swap - MTB BT	January 1, 2017 - December 31, 2018(3)
500	bbls/d	US $32.76	Swap - MTB BT	January 1, 2017 - December 31, 2019(3)
500	bbls/d	US $31.50	Swap - MTB BT	October 1, 2017 - March 31, 2018(3)
500	bbls/d	US $29.82	Swap - MTB BT	January 1, 2018 - December 31, 2018(3)
500	bbls/d	US $29.40	Swap - MTB BT	April 1, 2018 - December 31, 2018(3)
500	bbls/d	US $30.66	Swap - MTB BT	January 1, 2019 - December 31, 2019(3)
1,000	bbls/d	US 40.0%	Swap - CNWY PN/WTI	January 1, 2017 - March 31, 2017(4)
1,000	bbls/d	US 54.9%	Swap - CNWY PN/WTI	January 1, 2017 - December 31, 2017(4)
1,000	bbls/d	US $23.00	Swap - CNWY PN	January 1, 2017 - December 31, 2017(5)
1,000	bbls/d	US $20.63	Swap - CNWY PN	January 1, 2017 - December 31, 2018(5)
500	bbls/d	US $21.00	Swap - CNWY PN	April 1, 2017 - March 31, 2018(5)
500	bbls/d	US $22.26	Swap - CNWY PN	January 1, 2018 - December 31, 2018(5)
500	bbls/d	US $24.78	Swap - CNWY PN	January 1, 2018 - December 31, 2019(5)
500	bbls/d	US $22.05	Swap - CNWY PN	July 1, 2018 - December 31, 2018(5)
500	bbls/d	US $23.21	Swap - CNWY PN	January 1, 2019 - December 31, 2019(5)
500	bbls/d	US $(2.75)	Swap - WTI-MSW	January 1, 2017 - December 31, 2017

(1) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 5,000 gjs/d on the last trade date of each month for the duration of the contract.
(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) Mont Belvieu 65 nC4/35 iC4 price.
(4) Conway propane price as a percentage of WTI.
(5) Conway propane price.
(6) Includes an extendable feature on 5,275 gjs/d, which at the discretion of the counterparty would continue the term of the contract to December 31, 2018.

Volume		Price	Contract	Term
Oil contracts				
1,000	bbls/d	US $58.25	Swap - WTI	January 1, 2017 - June 30, 2017
1,500	bbls/d	CDN $67.05	Swap - WTI	January 1, 2017 - December 31, 2017
500	bbls/d	US $49.50	Swap - WTI	January 1, 2017 - December 31, 2017
500	bbls/d	CDN $70.10	Swap - WTI	January 1, 2017 - December 31, 2018
500	bbls/d	US $49.00	Swap - WTI	January 1, 2017 - December 31, 2018
500	bbls/d	CDN $71.61	Swap - WTI	January 1, 2017 - December 31, 2019
1,000	bbls/d	CDN $70.20	Swap - WTI	January 1, 2018 - December 31, 2018
500	bbls/d	US $51.00	Swap - WTI	January 1, 2018 - December 31, 2018
1,000	bbls/d	CDN $68.92	Swap - WTI	January 1, 2018 - December 31, 2019
1,000	bbls/d	CDN $70.25	Swap - WTI	January 1, 2019 - December 31, 2019
500	bbls/d	CDN $65.00	Sold Call - WTI	January 1, 2018 - December 31, 2018

Subsequent to December 31, 2016, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
500	bbls/d	US $25.73	Swap - CNWY PN	January 1, 2018 - December 31, 2019(1)
500	bbls/d	US $33.60	Swap - MTB BT	January 1, 2019 - December 31, 2019(2)
10,550	gjs/d	US $(0.77)	Swap - AECO Basis	January 1, 2018 - December 31, 2018
10,550	gjs/d	US $4.00	Sold Call - NYMEX	January 1, 2018 - December 31, 2018

(1) Conway propane price.
(2) Mont Belvieu 65 nC4/35 iC4 price.

At December 31, 2016, Bonavista had entered into the following contracts to purchase electricity:

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

At December 31, 2016, the fair market value recorded on the consolidated statement of financial position for these financial instrument commodity contracts was a net liability of $81.4 million compared to a net asset of $80.5 million at December 31, 2015. Of the $81.4 million net liability balance at December 31, 2016, a net liability of $48.5 million relates to financial instrument commodity contracts with term dates within one year and a net liability of $33.0 million relates to financial instrument commodity contracts with term dates beyond one year.

For the year ended December 31, 2016, the financial instrument commodity contracts in place under Bonavista's risk management program resulted in a net loss of $70.2 million, consisting of a realized gain of $91.8 million and an unrealized loss of $161.9 million. The realized gain of $91.8 million consisted of a $72.8 million gain on natural gas commodity derivative contracts, a $19.9 million gain on oil commodity derivative contracts offset by a $0.9 million loss on natural gas liquids commodity derivative contracts. For the same period of 2015, the financial instrument commodity contracts in place 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 an $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 three months ended December 31, 2016, the financial instrument commodity contracts in place under Bonavista's risk management program resulted in a net loss of $90.1 million, consisting of a realized gain of $9.7 million and an unrealized loss of $99.8 million. The realized gain of $9.7 million consisted of a $7.1 million gain on natural gas commodity derivative contracts, a $3.5 million gain on oil commodity derivative contracts, offset by a $1.0 million loss on natural gas liquids commodity derivative contracts. For the same period of 2015, the financial instrument commodity contracts in place 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 an $18.1 million gain on oil 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,	
	2016	2015	**2016**	2015
($ thousands)				
Natural gas	**7,098**	22,688	**72,839**	82,882
Natural gas liquids	**(964)**	1,145	**(931)**	6,964
Oil	**3,549**	18,091	**19,864**	59,307
Realized gains on financial instrument commodity contracts	**9,683**	41,924	**91,772**	149,153
Unrealized losses on financial instrument commodity contracts	**(99,807)**	(14,231)	**(161,930)**	(73,370)
Net gains (losses) on financial instrument commodity contracts	**(90,124)**	27,693	**(70,158)**	75,783

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, 2016 due to a $0.10 change in the price per thousand cubic feet of natural gas at AECO, would have impacted net loss and comprehensive loss of approximately $8.7 million compared to a sensitivity of $7.9 million for the comparable period of 2015. The change in fair value for those oil financial instrument commodity contracts in place at December 31, 2016 due to a $1.00 change in the price per barrel of oil at WTI would have impacted net loss and comprehensive loss of approximately $2.9 million compared to a sensitivity of $1.0 million for the comparable period of 2015.

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, 2016:

Volume		Price	Term
40,000	gjs/d	CDN $3.18	January 1, 2017 - December 31, 2017(1)(2)
15,000	gjs/d	CDN $2.79	April 1, 2017 - October 31, 2017(1)
20,000	gjs/d	CDN $3.00	January 1, 2018 - December 31, 2018(1)
10,000	gjs/d	CDN $2.75	April 1, 2018 - October 31, 2018

(1) 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.
(2) 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 5, 2017	US$ purchased forward	$12,500,000	1.3120
November 2, 2017	US$ purchased forward	$90,000,000	1.3136
November 2, 2020	US$ purchased forward	$160,000,000	1.3049
October 25, 2021	US$ purchased forward	$150,000,000	1.2991
November 2, 2022	US$ purchased forward	$50,000,000	1.3012
May 23, 2023	US$ purchased forward	$40,000,000	1.2974

The fair value recorded on the consolidated statement of financial position for these financial instrument contracts at December 31, 2016 was a net asset of $4.4 million of which $2.5 million relates to financial instrument contracts with term dates within one year and $1.9 million relate to financial instrument contracts with term dates beyond one year.

For the year ended December 31, 2016, an unrealized loss of $66.4 million was recorded on the consolidated statement of loss and comprehensive loss, compared to an unrealized gain of $54.7 million in the same period of 2015. During the year ended December 31, 2016, Bonavista reduced its exposure to foreign exchange fluctuations on outstanding instrument contracts by monetizing all positions and re-couponing at the then current market rates. As a result of these transactions a realized gain of $48.1 million was recognized during the year. At December 31, 2016 a $0.01 change in the CDN$/US$ exchange rate would have had an impact of approximately $3.7 million on net loss and comprehensive loss.

For the three months ended December 31, 2016, an unrealized gain of $7.7 million was recorded in the consolidated statement of loss and comprehensive loss, compared to an unrealized gain of $9.1 million in the same period of 2015. The unrealized gain for the three months ended December 31, 2016 and December 31, 2015, resulted from the weakening of the CDN dollar relative to the US dollar.

Royalties - For the year ended December 31, 2016 royalties decreased 32% to $36.9 million from $54.2 million for the year ended December 31, 2015, largely attributable to a 14% decrease in production volumes and a 14% reduction in production revenues on a per boe basis. Royalties as a percentage of production revenues were 8.3% for the year ended December 31, 2016 compared to 9.0% of production revenues for the year ended December 31, 2015. The reduction in royalties as a percentage of production revenues for the year ended December 31, 2016, was largely due to a 26% decrease in production revenues and the impact of lower commodity pricing on crown royalty calculations.

Natural gas royalties as a percentage of natural gas production revenues for the year ended December 31, 2016 were 3.0% compared to 5.5% for the year ended December 31, 2015. The decrease in natural gas royalties as a percentage of revenue reflects the lower reference prices used in the calculation of crown royalty obligations. In addition, stronger realized commodity prices in comparison to crown reference pricing resulted in further reductions to Bonavista's royalties as a percentage of production revenues. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the year ended December 31, 2016 were 17.3% compared to 16.6% for the comparable period of 2015 resulting from increased royalty encumbrances from the completion of royalty exemptions in addition to the acquisition of certain natural gas and natural gas liquid weighted assets in Bonavista's core areas which carried slightly higher average natural gas liquids royalty rates. Oil royalties as a percentage of oil production revenues for the year ended December 31, 2016 were lower at 9.9% compared to 10.9% for the year ended December 31, 2015, as a result of the disposition of non-core light oil weighted assets in the third quarter of 2016.

For the three months ended December 31, 2016, royalties increased 12% to $12.8 million from $11.4 million for the comparable period of 2015. Royalties as a percentage of production revenues were 9.0% for the three months ended December 31, 2016 compared to 8.3% for the same period of 2015. The increase in royalties on an absolute basis and as a percentage of production revenues was largely due to a 3% increase in production revenues in addition to the change in the composition of Bonavista's revenue to a larger natural gas liquids weighting which attracts higher royalty rates.

For the three months ended December 31, 2016, natural gas royalties as a percentage of natural gas production revenues were 3.3% compared to 4.7% for the three months ended December 31, 2015, resulting from lower reference prices used in the calculation of crown royalties. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the three months ended December 31, 2016 were 17.9% compared to 15.0% for the same period of 2015 resulting from increased royalty encumbrances from the completion of royalty exemptions in addition to the acquisition impact detailed above. Oil royalties as a percentage of oil production revenues for the three months ended December 31, 2016 decreased to 10.1% from 10.4% for the comparative 2015 period, as a result of the disposition of non-core light oil weighted assets in the third quarter of 2016.

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,		
	2016	2015	% Change	**2016**	2015	% Change
Natural gas ($/mcf):						
Royalties	**0.10**	0.13	(23)%	**0.07**	0.16	(56)%
% of Production revenues(1)	**3.3%**	4.7%	(1.4)%	**3.0%**	5.5%	(2.5)%
Natural gas liquids ($/bbl):						
Royalties	**4.71**	2.82	67 %	**3.48**	3.66	(5)%
% of Production revenues(1)	**17.9%**	15.0%	2.9 %	**17.3%**	16.6%	0.7 %
Oil ($/bbl):						
Royalties	**5.66**	4.85	17 %	**4.68**	5.63	(17)%
% of Production revenues(1)	**10.1%**	10.4%	(0.3)%	**9.9%**	10.9%	(1.0)%
Total ($/boe):						
Royalties	**2.00**	1.55	29 %	**1.47**	1.87	(21)%
% of Production revenues(1)	**9.0%**	8.3%	0.7 %	**8.3%**	9.0%	(0.7)%

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

In 2016, the provincial government of Alberta announced the Modernized Royalty Framework ("MRF") that became effective on January 1, 2017. The MRF is intended to modernize and simplify the existing royalty structure. The MRF will not impact the royalty structure of wells drilled prior to January 2017 for a ten year period, unless a producer applies to opt in to the MRF for wells that would have otherwise not been drilled. The most significant changes resulting from the MRF include the replacement of royalty credits and holidays on conventional wells through a Drilling and Completion Cost Allowance, a post-payout royalty rate based on commodity prices, and the reduction of royalty rates for mature wells. Bonavista expects that the MRF will improve the drilling economics of certain wells in its core areas, the most significant of which is expected to be in the development of our Falher play in West Central Alberta.

Operating expenses - For the year ended December 31, 2016, operating expenses decreased 26% to $140.6 million compared to $190.9 million for the year ended December 31, 2015. On a per boe basis, operating expenses decreased 15% to $5.60 per boe for the year ended December 31, 2016 compared to $6.60 per boe for the year ended December 31, 2015. The decrease in operating expenses on an absolute and per boe basis resulted from the disposition of higher cost non-core assets, focused cost control initiatives and the concentration of activity in Bonavista's operationally efficient core areas. In addition, overall cost structure reductions have been realized from the commissioning of Bonavista's Ansell facility in late 2015. These decreases were partially offset by the short-term impact arising from the acquisition of certain natural gas and natural gas liquid weighted assets in Bonavista's core areas in the fourth quarter of 2016, which were acquired with an initial cost structure that was greater than Bonavista's core operating cost structure. The percentage decrease in absolute operating expenses exceeded the percentage decrease on a per boe basis due to the impact of fixed cost components within overall operating expenditures.

Operating expenses for the three months ended December 31, 2016 decreased 15% to $36.7 million compared to $43.0 million for the same period of 2015. On a per boe basis, operating expenses decreased 2% to $5.75 per boe for the three months ended December 31, 2016 compared to $5.85 per boe for the comparable period of 2015. The decrease in operating expenses on an absolute and per boe basis resulted from the disposition of higher cost non-core assets in addition to efficiencies realized through Bonavista's asset concentration strategy. These decreases were partially offset by the impact of the acquisition of core area properties completed in the fourth quarter of 2016 as detailed above.

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,		
	2016	2015	% Change	**2016**	2015	% Change
Natural gas ($/mcf)	**0.90**	0.85	6 %	**0.86**	0.98	(12)%
Natural gas liquids ($/bbl)	**5.88**	5.79	2 %	**5.68**	7.18	(21)%
Oil ($/bbl)	**10.65**	11.01	(3)%	**10.88**	11.10	(2)%
Total ($/boe)	**5.75**	5.85	(2)%	**5.60**	6.60	(15)%

In the fourth quarter of 2015, the provincial government of Alberta released its Climate Leadership Plan which will impact businesses that contribute to carbon emissions in Alberta. The plan includes imposing carbon pricing that is applied across all sectors, starting at $20 per tonne on January 1, 2017 and moving to $30 per tonne on January 1, 2018, the phase-out of coal-fired power generation by 2030, a cap on oil sands emissions production of 100 megatonnes, and a 45 percent reduction in methane emissions by the oil and gas sector by 2025. Prior to 2023, the plan is expected to have a minimal impact on Bonavista's operations as carbon tax exemptions are available for fuel that is used, flared, or vented in a production process and sold to a consumer for use in an oil and gas production process. Bonavista is continuing to monitor developments of this plan for periods after 2023 and will evaluate the expected impact on its operations.

In the third quarter of 2016, the Government of Canada announced its proposed plan to the pricing of carbon emissions for all Canadian jurisdictions. The plan includes imposing carbon pricing beginning at a minimum of $10 per tonne in 2018 and rising by $10 per tonne each year to $50 per tonne in 2022. Provinces and territories have a year to introduce their own carbon pricing or adopt a cap-and-trade system that meets or exceeds the federal benchmark. If provinces and territories fail to implement a price or cap-and-trade plan by 2018, the Government of Canada will implement a price in that jurisdiction. Bonavista is currently monitoring the developments of this plan and will evaluate the expected impact of the plan on its operations.

Transportation expenses - For the year ended December 31, 2016, transportation expenses decreased 38% to $22.6 million compared to $36.5 million for the year ended December 31, 2015. On a per boe basis, transportation expenses decreased 29% to $0.90 per boe for the year ended December 31, 2016 compared to $1.26 per boe for the year ended December 31, 2015. The decrease in transportation expenses on both an absolute and per boe basis was largely due to a change in custody transfer points resulting from a third-party gas management agreement effective January 1, 2016 in addition to the disposition of non-core properties with higher associated average transportation rates. Transportation expenses on a per boe basis were also impacted by Bonavista's increased natural gas and natural gas liquids production profile which carry lower transportation costs per boe compared to transportation costs per boe for light oil production.

Transportation expenses for the three months ended December 31, 2016, decreased 39% to $5.5 million compared to $9.0 million for the same period of 2015. On a per boe basis, transportation expenses for the three months ended December 31, 2016 decreased 30% to $0.86 per boe from $1.23 per boe for the comparable period of 2015. The decrease in transportation costs on an absolute and per boe basis during the fourth quarter of 2016 was due to the same factors discussed above.

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,		
	2016	2015	% Change	**2016**	2015	% Change
Natural gas ($/mcf)	**0.17**	0.25	(32)%	**0.17**	0.24	(29)%
Natural gas liquids ($/bbl)	**0.54**	0.34	59 %	**0.53**	0.48	10 %
Oil ($/bbl)	**0.86**	1.85	(54)%	**1.33**	1.90	(30)%
Total ($/boe)	**0.86**	1.23	(30)%	**0.90**	1.26	(29)%

Operating Netbacks - For the year ended December 31, 2016, Bonavista's operating netback decreased 17% to $13.44 per boe compared to $16.16 per boe for the year ended December 31, 2015. For the three months ended December 31, 2016, Bonavista's operating netback decreased 4% to $15.14 per boe compared to $15.76 per boe for the same period of 2015. The decrease in Bonavista's 2016 operating netback on a per boe basis for the three months and year ended December 31, 2016 was primarily due to lower realized commodity pricing. In spite of the challenging commodity price environment Bonavista's operating margin(1) showed modest improvement to 63% for the year ended December 31, 2016 compared to 62% for the year ended December 31, 2015.

(1) Operating margin 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. Bonavista has calculated operating margin as production revenues and realized gains on financial instruments commodity contracts less royalties, operating costs and transportation costs; divided by production revenue and realized gains on financial instrument commodity contracts.

The following tables highlight Bonavista's operating netbacks per boe by core area for the three months and years ended December 31 ($/boe):

	Three months ended December 31, 2016				Three months ended December 31, 2015			
	West Central	Deep Basin	Other	Total	West Central	Deep Basin	Other	Total
Production revenues	**22.58**	**23.03**	**13.13**	**22.24**	18.92	18.33	18.07	18.68
Realized gains on financial instrument commodity contracts(1)	**—**	**—**	**—**	**1.51**	—	—	—	5.71
	22.58	**23.03**	**13.13**	**23.75**	18.92	18.33	18.07	24.39
Royalties	**2.24**	**1.64**	**1.21**	**2.00**	1.73	1.02	1.72	1.55
Operating expense	**5.56**	**5.42**	**10.20**	**5.75**	5.72	4.12	10.70	5.85
Transportation expense	**0.60**	**1.43**	**0.63**	**0.86**	0.63	1.22	4.88	1.23
Total operating netback(2)(3)	**14.18**	**14.54**	**1.09**	**15.14**	10.84	11.97	0.77	15.76

	Years ended December 31, 2016				Years ended December 31, 2015			
	West Central	Deep Basin	Other	Total	West Central	Deep Basin	Other	Total
Production revenues	**18.00**	**18.23**	**13.79**	**17.75**	21.17	19.38	21.50	20.73
Realized gains on financial instrument commodity contracts(1)	**—**	**—**	**—**	**3.66**	—	—	—	5.15
	18.00	**18.23**	**13.79**	**21.41**	21.17	19.38	21.50	25.88
Royalties	**1.69**	**0.86**	**1.86**	**1.47**	2.04	1.41	2.04	1.87
Operating expense	**5.47**	**4.21**	**12.11**	**5.60**	6.53	4.70	11.23	6.60
Transportation expense	**0.65**	**1.43**	**1.02**	**0.90**	0.67	1.21	4.35	1.26
Total operating netback(2)(3)	**10.19**	**11.73**	**(1.20)**	**13.44**	11.93	12.06	3.88	16.16

(1) Amounts are not allocated by area.
(2) Amounts may not add due to rounding.
(3) Operating netbacks 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.

General and administrative expenses - General and administrative expenses, after overhead recoveries, decreased 16% to $27.1 million for the year ended December 31, 2016 compared to $32.5 million for the year ended December 31, 2015. On a per boe basis, general and administrative expenses decreased to $1.08 per boe for the year ended December 31, 2016 compared to $1.12 per boe for the year ended December 31, 2015. The decrease in general and administration expenses on an absolute and per boe basis resulted from a decrease in Bonavista's administrative cost structure and reduced discretionary spending throughout 2016 relative to 2015.

General and administrative expenses, after overhead recoveries, was $6.9 million for the three months ended December 31, 2016, a 2% decrease compared to $7.1 million for the comparable period of 2015. The decrease in general and administrative expenses on an absolute basis resulted primarily from the reduction in Bonavista's administrative cost structure contributing to lower staffing levels and cash compensation, partially offset by professional services received in connection with fourth quarter acquisition and disposition transactions. On a per boe basis, general and administration expenses increased 12% to $1.09 per boe for the three months ended December 31, 2016 compared to $0.97 per boe for the same period of 2015, due to a 13% decrease in production volumes.

Share-based compensation - Share-based compensation expense recognized in connection with Bonavista's stock option, restricted share award, restricted incentive award and performance incentive award plans ("long-term incentive plans"), for the year ended December 31, 2016 was $9.0 million compared to $17.2 million recognized for the year ended December 31, 2015. For the year ended December 31, 2016, $0.8 million of share-based compensation expense was capitalized to property, plant and equipment compared to $1.7 million for the same period of 2015.

Share-based compensation expense recognized for the three months ended December 31, 2016 was $2.1 million compared to $4.1 million recognized for the same period of 2015. For the three months ended December 31, 2016 and December 31, 2015, $0.2 million and $0.5 million of share-based compensation expense was capitalized to property, plant and equipment respectively. Share-based compensation expense was lower for the three months and year ended December 31, 2016, when compared to the same periods of 2015 due to the lower fair value associated with the outstanding restricted incentive awards expensed in 2016 and the impact of additional expense recognized throughout 2015 for stock options voluntarily surrendered by Bonavista's employees.

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,	
	2016	2015	**2016**	2015
($ thousands, except for per boe amounts)				
Share-based compensation expense	**2,058**	4,057	**8,994**	17,157
Share-based compensation expense per boe	**0.32**	0.55	**0.36**	0.59

Depletion, depreciation, amortization and impairment - For the year ended December 31, 2016, depletion, depreciation, amortization and impairment expense decreased 73% to $319.8 million from $1,168.0 million for the year ended December 31, 2015. On a per boe basis, depletion, depreciation, amortization and impairment expense was $12.75 per boe for 2016 and $40.36 per boe for 2015. The significant decrease in depletion, depreciation, amortization and impairment on both an absolute and per boe basis was due to the impact of an $812.0 million impairment charge recorded for the year ended December 31, 2015 and to a lesser extent the impact of a 14% decrease in production volumes of which depletion is based upon.

In the second quarter of 2016, Bonavista had classified certain non-core properties in its Southern Alberta CGU as assets held for sale, as a result, an impairment charge of $56.6 million was recorded using the fair value less cost to sell model based on the estimated consideration to be received according to the purchase and sale agreement. These Southern Alberta assets were disposed of in the third quarter of 2016 resulting in the disposition of Bonavista's Southern Alberta CGU in its entirety. At December 31, 2016, Bonavista evaluated its property, plant and equipment for indicators of any potential impairment or related reversal. No indicators of impairment were identified and as a result no impairment test was performed.

For the three months ended December 31, 2016, depletion, depreciation, amortization and impairment decreased 90% to $64.3 million from $649.2 million for the same period of 2015. On a per boe basis, depletion, depreciation, amortization and impairment was $10.08 per boe for the three months ended December 31, 2016 compared to $88.36 per boe for the same period of 2015. The decrease in depletion, depreciation, amortization and impairment on both an absolute and per boe basis was largely due to the impact of the 2015 impairment charge discussed above in addition to a 13% decrease in production volumes.

For the year ended December 31, 2016, depletion, depreciation and amortization expense, excluding the impact of impairment, decreased 26% to $263.2 million for the year ended December 31, 2016 from $356.0 million for the year ended December 31, 2015. The decrease in depletion, depreciation and amortization expense was due to a reduction in the carrying value of property, plant and equipment as a result of the 2015 impairment charge and the impact of a 14% decrease in production volumes. On a per boe basis, depletion, depreciation and amortization expense, excluding the impact of impairment, for the year ended December 31, 2016 decreased to $10.49 per boe compared to $12.30 per boe for the year ended December 31, 2015.

For the three months ended December 31, 2016, depletion, depreciation and amortization expense, excluding the impact of impairment, decreased 26% to $64.3 million from $86.9 million due to a reduction in the carrying value of property, plant and equipment as a result of the 2015 impairment charge and the impact of a 13% decrease in production volumes. On a per boe basis, depletion, depreciation and amortization expense, excluding the impact of impairment, for the three months ended December 31, 2016 was $10.08 per boe compared to $11.83 per boe for the same period of 2015 for similar reasons as discussed above.

Net financing costs - Net financing costs decreased to $44.3 million for the year ended December 31, 2016, from $166.6 million for the year ended December 31, 2015. The decrease can be largely attributed to unrealized foreign exchange gains and losses associated with the revaluation of Bonavista's US denominated senior unsecured notes offset by unrealized gains and losses on Bonavista's financial instrument contracts. For the year ended December 31, 2016, a $36.4 million unrealized foreign exchange gain was recognized on the revaluation of Bonavista's US denominated senior unsecured notes compared to an unrealized foreign exchange loss of $157.9 million for the year ended December 31, 2015. For the year ended December 31, 2016, a $66.4 million unrealized loss and a $48.1 million realized gain was recognized on financial instrument contracts compared to an unrealized gain on financial instrument contracts of $54.7 million for the year ended December 31, 2015. The realized gain on financial instrument contracts resulted from the monetization of Bonavista financial instrument contracts in the third quarter of 2016. For the year ended December 31, 2016, net financing costs on a per boe basis decreased to $1.76 per boe compared to net financing costs of $5.76 per boe for the year ended December 31, 2015 for the same reason as stated above.

Net financing costs, excluding non-cash amounts and the realized gain on financial instrument contracts, decreased 8% to $45.6 million for the year ended December 31, 2016, compared to $49.7 million for the year ended December 31, 2015. The decrease in net financing costs, excluding non-cash amounts and the realized gain on financial instrument contracts, was due to a 27% reduction in Bonavista's long-term debt resulting in lower associated interest costs. Net financing costs on a per boe basis, excluding non-cash amounts and the realized gain on financial instrument contracts, increased 6% to $1.82 per boe for the year ended December 31, 2016 compared to $1.72 per boe for the year ended December 31, 2015, largely due to a 14% decrease in production volumes.

Net financing costs decreased 36% to $26.9 million for the three months ended December 31, 2016, from net financing costs of $42.1 million for the same period of 2015. The decrease can be largely attributed to a lower unrealized foreign exchange loss associated with the revaluation of Bonavista's US denominated senior unsecured notes. Similarly, for the three months ended December 31, 2016, net financing costs on a per boe basis decreased 27% to $4.21 per boe compared to $5.73 per boe recognized in the same period of 2015, for similar reasons as stated above.

Net financing costs, excluding non-cash amounts, decreased 16% to $10.9 million for the three months ended December 31, 2016, compared to $12.9 million for the three months ended December 31, 2015. The decrease in net financing costs, excluding non-cash amounts, was due to a 27% reduction in Bonavista's long-term debt resulting in lower associated interest costs. For the three months ended December 31, 2016, net financing costs, excluding non-cash amounts, on a per boe basis decreased 3% to $1.70 per boe compared to $1.75 per boe recognized for the same period of 2015. On a per boe basis, net financing costs, excluding non-cash amounts, decreased to a lesser extent than on an absolute basis due to a 13% decrease in production volumes.

Deferred income tax (recovery) - For the year ended December 31, 2016, a deferred income tax recovery of $38.9 million was recognized compared to a deferred income tax recovery of $204.1 million for the year ended December 31, 2015. For the three months ended December 31, 2016, a provision of $0.7 million was recognized compared to a deferred income tax recovery of $155.3 million recognized for the same period of 2015. The deferred income tax recovery for the year ended December 31, 2016 was less 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 and the income tax treatment of non-deductible share-based compensation expense. The deferred income tax provision for the three months ended December 31, 2016 was higher than the provision calculated using the statutory rate due to the same reasons noted above. Bonavista made no cash payments or tax installments for the three months or year ended December 31, 2016 or for the comparative periods of 2015.

Funds from operations, net loss and comprehensive loss - For the year ended December 31, 2016, funds from operations decreased 31% to $264.4 million ($1.11 per share, basic) from $385.4 million ($1.77 per share, basic) for the year ended December 31, 2015. The decrease in funds from operations was primarily due to a 28% decrease in production revenues, including the impact of realized gains on financial instrument commodity contracts, partially offset by a 32% decrease in royalties, a 26% decrease in operating expenses and a 38% decrease in transportation expenses.

For the three months ended December 31, 2016, Bonavista experienced an 18% decrease in funds from operations to $78.7 million ($0.31 per share, basic) from $95.8 million ($0.44 per share, basic) for the same period of 2015. The decrease in funds from operations resulted primarily from a 15% decrease in production revenues, including the impact of realized gains on financial instrument commodity contracts, partially offset by a 15% improvement in absolute operating expenses and a 39% decrease in transportation expenses.

The following table is a reconciliation of a cash flow from operating activities to funds from operations:

	Three months ended December 31,		Years ended December 31,	
Calculation of Funds From Operations:	**2016**	2015	**2016**	2015
($ thousands)				
Cash flow from operating activities	**70,761**	126,735	**260,792**	406,290
Interest expense[1]	**(10,856)**	(12,860)	**(45,616)**	(49,716)
Decommissioning expenditures	**6,637**	3,281	**15,309**	18,925
Changes in non-cash working capital	**12,200**	(21,364)	**33,906**	9,852
Funds from operations[2]	**78,742**	95,792	**264,391**	385,351

(1) Accrued interest expense on Bonavista's long-term debt excluding the amortization of debt issuance costs.
(2) 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.

Bonavista recorded a net loss and comprehensive loss for the year ended December 31, 2016 of $96.0 million ($0.40 per share, basic) compared to a net loss and comprehensive loss of $751.5 million ($3.45 per share, basic) for the same period of 2015. The net loss and comprehensive loss was higher in 2015, largely as a result of an $812.0 million impairment charge recognized during the year, as a result of a sustained decline in commodity prices.

Bonavista recorded a net loss and comprehensive loss for the three months ended December 31, 2016 of $12.0 million ($0.05 per share, basic) compared to a net loss and comprehensive loss of $454.6 million ($2.09 per share, basic) for the comparable period of 2015. The net loss and comprehensive loss was higher in 2015, largely as a result of a $562.0 million impairment charge recognized during the fourth quarter of 2015 as a result of a sustained decline in commodity prices.

Capital expenditures - Capital expenditures in 2016 were focused on the development of the Glauconite and Falher plays in the West Central core area and the Wilrich and Bluesky plays in the Deep Basin core area, supporting Bonavista's concentration strategy. For the year ended December 31, 2016, Bonavista's investment in exploration and development activities was $153.9 million, a 51% reduction compared to the $313.9 million spent for the year ended December 31, 2015. The decrease in exploration and development expenditures, aligns with Bonavista's objective to allocate excess funds from operations in 2016 to reduce long-term debt and improve financial flexibility. Bonavista's exploration and development expenditures represented 58% of Bonavista's funds from operations for the year ended December 31, 2016 compared to 81% for the year ended December 31, 2015. For the three months ended December 31, 2016, Bonavista's investment in exploration and development activities was $58.6 million, representing 74% of funds from operations for the period and a 4% increase compared to $56.1 million for the same period of 2015. The investment in exploration and development activities in the fourth quarter of 2016 was supported by net proceeds received from non-core asset dispositions, as discussed below. Bonavista remains focused on capital discipline and efficiency to maintain capital spending that is lower than funds from operations.

For the year ended December 31, 2016, cash proceeds from non-core dispositions totaled $180.1 million, resulting in a gain on sale of property, plant and equipment of $34.3 million and a $1.9 million loss on sale of exploration and evaluation assets. The non-core assets disposed were predominately located in the Willesden Green, Garrington and Lethbridge areas of Alberta. During the comparative year ended December 31, 2015, Bonavista disposed of certain non-core petroleum and natural gas rights through asset exchanges and other property dispositions for proceeds of $100.1 million, resulting in a $19.9 million gain on sale of property, plant and equipment and a $14.5 million gain on the sale of exploration and evaluation assets. During the year ended December 31, 2016, Bonavista also acquired, through property acquisitions, certain properties and petroleum and natural gas rights within its core areas for a cash consideration of $12.2 million for the year ended December 31, 2016 compared to $69.6 million for the year ended December 31, 2015. The acquired assets in both 2016 and 2015 were predominately located in west central Alberta near Edson and Ansell within the Deep Basin core area.

In fourth quarter of 2016, Bonavista also completed an asset exchange whereby certain properties and petroleum and natural gas rights were acquired within the Deep Basin and West Central core areas in exchange for non-core assets in the Blueberry area of northeast British Columbia. The carrying value of the Blueberry assets disposed was $83.9 million and the fair value of the core area assets acquired was $141.6 million, resulting in a gain on the exchange of $57.7 million. The asset exchange resulted in a gain due to the fair value of the assets received being greater than the carrying value of the assets disposed, as a result of both Bonavista and its counterparty being motivated to acquire assets that aligned with strategic objectives to enhance development in core areas.

During the three months ended December 31, 2016, Bonavista successfully disposed of certain non-core assets for cash proceeds of $120.2 million compared to disposition proceeds of $7.1 million for the comparable period of 2015. During the three month period ended December 31, 2016, Bonavista acquired liquids rich natural gas weighted assets in its core areas for a cash consideration of $2.6 million compared to an investment of $1.6 million for the acquisition of certain natural gas weighted assets in the Ansell area of its Deep Basin core area during the three months ended December 31, 2015. During the three months ended December 31, 2016, Bonavista also completed the asset exchange as described above.

Head office capital expenditures for the year ended December 31, 2016 were lower at $0.6 million compared to $1.2 million spent in 2015 due to reduced discretionary spending. Head office capital expenditures for the three months ended December 31, 2016 and December 31, 2015 were consistent at $0.1 million.

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,	
	2016	2015	**2016**	2015
($ thousands)				
Land acquisitions	**1,033**	1,507	**2,840**	7,823
Geological and geophysical	**1,049**	1,233	**4,174**	9,759
Drilling and completion	**44,973**	40,413	**121,540**	230,724
Production equipment and facilities	**11,519**	12,931	**25,317**	65,599
Exploration and development expenditures	**58,574**	56,084	**153,871**	313,905
Property acquisitions(1)	**92,929**	1,572	**102,540**	69,576
Property dispositions(2)	**(210,595)**	(7,112)	**(270,445)**	(100,128)
Head office expenditures	**110**	74	**604**	1,203
Net capital expenditures	**(58,982)**	50,618	**(13,430)**	284,556

(1) Property acquisitions include capital expenditures that occurred by way of cash property acquisitions and non-cash property acquisitions.
(2) Property dispositions include capital proceeds that were received by way of cash property dispositions and non-cash property dispositions.

Liquidity and capital resources - At December 31, 2016, net debt was $877.5 million with a debt to fourth quarter 2016 annualized funds from operations ratio of 2.8:1. 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 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 14 of the 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, 2016**	Year ended December 31, 2015
($ thousands)		
Long-Term Debt	**775,887**	1,231,031
Adjusted working capital deficiency(1)	**101,636**	79,632
Total net debt(2)	**877,523**	1,310,663
Funds from operations fourth quarter annualized	**314,968**	383,168
Total net debt to funds from operations	**2.8:1**	3.4:1
Funds from operations for the year ended	**264,391**	385,351
Total net debt to funds from operations	**3.3:1**	3.4:1

(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 a measures with other entities.

As at December 31, 2016 Bonavista was not drawn on the bank credit facility providing $600.0 million of unused borrowing capacity, in comparison at December 31, 2015 Bonavista's outstanding bank debt was $272.1 million. The average effective interest rate for bank debt throughout the year ended December 31, 2016 was approximately 4.2% compared to 3.8% for the year ended December 31, 2015.

Bonavista's senior unsecured notes totaled $930.2 million at December 31, 2016 consisting of US$680.0 million (CDN$913.0 million) and CDN$20.0 million of which US$25.0 million becomes due on June 5, 2017 and US$90.0 million becomes due on November 2, 2017. Bonavista plans to repay the current portion of its long-term debt through a combination of available cash, excess funds from operations and its bank credit facility. At December 31, 2016, Bonavista had an available cash balance of $86.0 million. Bonavista's senior unsecured notes bear fixed interest rates, with a weighted average rate of 4.1% for the years ended December 31, 2016 and 2015. The senior unsecured notes have a five year weighted average life with the majority of the debt repayments due in 2020 and thereafter.

At December 31, 2016 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, refer to note 14 of the financial statements. Total debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment (EBITDA) and total senior debt to EBITDA was 2.7 times compared to the covenant of 3.5 times and total debt to capitalization was 0.37 times compared to the covenant of 0.5 times.

A disciplined approach to enhance operating and capital efficiencies in 2016 has positioned Bonavista for future growth while remaining committed to enhancing financial flexibility and the prudent use of debt. For 2017, Bonavista plans to invest between $280 million and $300 million on its capital program within its core regions, to drill between 55 and 65 net wells.

Shareholders' equity - As at December 31, 2016, Bonavista had 253.9 million equivalent common shares outstanding. This includes 3.3 million exchangeable shares, which are exchangeable into 4.7 million common shares. The exchange ratio in effect at December 31, 2016 for exchangeable shares was 1.42923:1. As at March 2, 2017, Bonavista had 254.6 million equivalent common shares outstanding. This includes 3.3 million exchangeable shares, which are exchangeable into 4.7 million common shares. The exchange ratio in effect at March 2, 2017 for exchangeable shares was 1.43223:1. In addition, Bonavista has 0.1 million stock options as at March 2, 2017, with an average exercise price of $17.09 per common share and 5.0 million restricted incentive awards and 3.4 million performance incentive awards outstanding.

Dividends - For the year ended December 31, 2016, Bonavista declared dividends of $13.9 million ($0.06 per share) compared to $76.8 million ($0.37 per share) for the same period of 2015. For the three months ended December 31, 2016, Bonavista declared dividends of $2.5 million ($0.01 per share) compared to $11.7 million ($0.055 per share) for the same period of 2015. Bonavista announces and confirms its dividend policy on a quarterly basis. 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.

Annual financial information - The following table highlights selected annual financial information for each of the three years ended December 31, 2016, 2015 and 2014.

Years ended December 31	**2016**	2015	2014
($ thousands, except per share amounts)			
Consolidated Statement of Income (Loss) and Comprehensive Income (Loss) Information			
Production revenues, net of royalties	**408,531**	545,798	970,757
Funds from operations	**264,391**	385,351	561,105
per share - basic	**1.11**	1.77	2.69
per share - diluted	**1.09**	1.75	2.66
Net income (loss)	**(95,998)**	(751,545)	4,847
per share - basic	**(0.40)**	(3.45)	0.02
per share - diluted	**(0.40)**	(3.45)	0.02
Consolidated Statement of Financial Position Information			
Net capital expenditures	**(13,430)**	284,556	535,801
Total assets	**3,172,157**	3,523,716	4,429,402
Working capital deficiency[1]	**(150,112)**	(16,230)	(27,173)
Long-term debt	**775,887**	1,231,031	989,671
Shareholders' equity	**1,560,244**	1,548,266	2,357,706
Dividends declared	**13,891**	76,762	164,750

(1) Working capital deficiency excludes decommissioning liabilities.

Quarterly financial information - The following table highlights Bonavista's performance for the eight quarterly periods ending on March 31, 2015 to December 31, 2016:

	2016				2015			
	December 31	September 30	June 30	March 31	December 31	September 30	June 30	March 31
($ thousands, except per share amounts)								
Production revenues	141,842	108,206	90,908	104,478	137,260	148,342	150,110	164,287
Net income (loss)	(12,021)	(29,386)	(101,012)	46,421	(454,616)	(216,187)	(1,882)	(78,860)
Basic	(0.05)	(0.11)	(0.45)	0.21	(2.09)	(0.99)	(0.01)	(0.36)
Diluted	(0.05)	(0.11)	(0.45)	0.21	(2.09)	(0.99)	(0.01)	(0.36)

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 $46.4 million in the first quarter of 2016. These fluctuations are primarily influenced by production volumes, commodity prices, realized and unrealized gains and losses on financial instrument contracts, unrealized gains and losses on the revaluation of Bonavista's US dollar denominated senior unsecured notes, gains and losses on the acquisition and disposition of property, plant and equipment, gains and loss on the disposition of exploration and evaluations assets 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, 2016 and ending on December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the Corporation's internal controls over financial reporting. Management has concluded that Bonavista's internal control over financial reporting was effective as of December 31, 2016. This assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Future accounting policies - Below is a description of new IFRS standards 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.

- In April 2016, the IASB issued its final amendments to 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 model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is to be recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and timing of the revenue recognized. The new standard applies to contracts with customers and does not apply to insurance contracts, financial instruments or lease contracts. The new standard is to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with early adoption permitted. Bonavista intends to adopt IFRS 9 on a retrospective basis on January 1, 2018. Bonavista is currently in the process of identifying underlying revenue contracts with customers to determine the impact, if any, that the adoption of IFRS 15 will have on its financial statements.
- In July 2014, the IASB issued the complete IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9, 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 new standard is to be adopted retrospectively with some exemptions for annual periods on or after January 1, 2018, with early adoption permitted. Bonavista intends to adopt IFRS 9 on a retrospective basis on January 1, 2018. The extent of the adoption of IFRS 9 on the classification and measurement of the Corporation's financial assets and financial liabilities and related disclosures has not yet been determined. Bonavista does not currently apply hedge accounting to its financial instrument contracts and does not currently intend to apply hedge accounting to any of its financial instrument contracts upon adoption of IFRS 9.

- In January 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 new standard is to be adopted either retrospectively or using a modified retrospective approach. 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 3 of the Notes to the 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. During the third quarter of 2016, Bonavista disposed of all of the assets in its Southern Alberta CGU. There were no other changes to the composition of Bonavista's CGUs in 2016 or in the comparative 2015 year.
- *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. Bonavista also assesses its property, plant and equipment to determine if events or circumstances would support the reversal of any previously recorded impairment charges. In this assessment Bonavista considers the facts and circumstances that caused the original impairment charge to be recognized and whether there is a sustained period in which those facts and circumstances changed.

  At December 31, 2016, Bonavista evaluated each of its CGUs for indicators of potential impairment or a reversal of previously recorded impairment charges. There were no indicators of impairment identified and as such no impairment test was performed at December 31, 2016. Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal. If an impairment test had been conducted, management would have evaluated the net present values of each CGU. Key estimates used in the determination of cash flows used to calculate the net present value of a CGU, 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.

Non-GAAP Measures - Throughout Bonavista's MD&A and Message to Shareholders, the Corporation uses terms that are commonly used in the oil and natural gas industry, but do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other entities. Management believes that the presentation of these Non-GAAP measures provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze performance against prior periods on a comparable basis.

Management uses the following terms to analyze operating performance on a comparable basis with prior periods. "Operating netbacks" is equal to production revenues and realized gains and losses on financial instrument commodity contracts, less royalties, operating and transportation expenses calculated on a per boe basis. "Operating margin" is equal to production revenues and realized gains and losses on financial instrument commodity contracts less royalties, operating costs and transportation costs; divided by production revenues and realized gains and losses on financial instrument commodity contracts. Realized gains and losses on financial instrument commodity contracts represent the portion of Bonavista's financial instrument commodity contracts that have settled in cash during the period and disclosing this impact provides transparency on how Bonavista's risk management program impacts the netback and operating margin metrics. "Cash costs" is equal to the total of operating, transportation, general and administrative, and financing expenses calculated on a per boe basis. "Total boe equivalent" is calculated by multiplying the daily production by the number of days in the period. "Basic funds from operations per share" is equal to funds from operations (described below in Other Management Performance Measures) based on the weighted average number of common shares outstanding and includes the weighted average number of exchangeable shares which are convertible into common shares on certain terms and conditions.

Other Management Performance Measures - In addition to the Non-GAAP Measures described above, there are also terms that have been reconciled in Bonavista's financial statements to their most comparable IFRS measures. These terms do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other entities. These terms have been referenced in Bonavista's Annual Report. These terms are used by Bonavista's management to analyze operating performance on a comparable basis with prior periods and to analyze the liquidity of the Corporation.

"Funds from operations" 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. "Total net debt" is equal to the long-term portion of Bonavista's bank debt and senior unsecured notes, net of adjusted working capital deficiency. "Adjusted working capital deficiency" excludes the current assets and liabilities from financial instrument commodity contracts and decommissioning liabilities. "Total net debt to funds from operations" is equal to total net debt divided by funds from operations for the relevant period. "Annualized current quarter funds from operations" is equal to the identified quarters funds from operations annualized for the year.

Oil and Gas Advisories - In Bonavista's Annual Report management also makes reference to the following oil and gas terms "finding and development costs" ("F&D costs") and "finding, development and acquisition costs" ("FD&A costs"), "F&D recycle ratio", "FD&A recycle ratio" and "reserve life index" which have been prepared by management and do not have standardized meanings or standard calculations and therefore such measures may not be comparable to similar measures used by other entities. These terms are used by Bonavista's management to measure the success of replacing reserves and to compare operating performance to previous periods on a comparable basis. For additional information on these measures reference should also be made to Bonavista's Annual Information Form. Finding and development costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on development and exploration activities in the year by the change in reserves from the prior year for the reserve category. Finding development and acquisition costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on development and exploration activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category. Both finding and development costs and finding development and acquisition costs take into account reserve revisions during the year on a per boe basis. The F&D recycle ratio is calculated by dividing the operating netback (refer to Non-GAAP Measures) for the period by the F&D costs per boe for the particular reserve category. FD&A recycle ratio is calculated by dividing the operating netback (refer to Non-GAAP Measures) for the period by the FD&A costs per boe for the particular reserve category. Reserve life index is calculated based on the amount for the relevant reserve category divided by the production forecast as prepared by Bonavista's reserve engineers GLJ.

The Annual Report also refers to IRR (internal rate of return) and payout which have been prepared by management and are used to measure performance. These terms do not have standardized meanings or standard calculations and are not comparable to similar measures used by other entities. In this document internal rate of return refers to the discount rate that makes the net present value of all cash flows of a project equal zero and payout refers to the time required to pay back the capital expenditures (on a before tax basis) of a project. The Annual Report also refers to production efficiency which is defined as a type of capital efficiency that measures the cost to add an incremental barrel of flowing production. Specifically, for the average production efficiencies of our plays, Bonavista uses the total actual/projected drill, complete and tie-in capital divided by the total of the well initial twelve month production rate.

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are converted mathematically to equivalent barrels of oil (boe). We use the industry-accepted standard conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio is based on an energy equivalency conversion method primarily applicable at the burner tip. It does not represent a value equivalency at the wellhead and is not based on either energy content or current prices. While the boe ratio is useful for comparative measures and observing trends, it does not accurately reflect individual product values and might be misleading, particularly if used in isolation. As well, given that the value ratio, based on the current price of crude oil to natural gas, is significantly different from the 6:1 energy equivalency ratio, using a 6:1 conversion ratio may be misleading as an indication of value.

Forward-Looking Statements - This Annual Report contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words “anticipate”, “except”, “project”, “plan”, “estimate”, “budget”, “will”, “strategy”, “ongoing”, “potential”, “believe”, “continue" and similar expressions are intended to identify forward-looking information. Any "financial outlook" or "future orientated financial information" in the Annual Report, as defined by applicable securities laws, has been approved by the management of Bonavista. Such financial outlook or future orientated financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

In particular, but without limiting the foregoing, this document contains forward-looking information pertaining to the following:

- Forecasted capital expenditures for 2017 including drilling, exploration and development plans, acquisition and disposition activities and expected future drilling locations;
- Expected development economics for certain properties in 2017;
- Expected 2017 total and fourth quarter average production volumes and anticipated product mix;
- Expected 2017 oil, gas and natural gas liquids production volumes;
- Expected realized oil, gas and natural gas liquids prices and the differentials resulting from our financial risk management program in 2017;
- The benefits of Bonavista's hedging portfolio;
- Expected 2017 funds from operations;
- Anticipated rate of return and future payout;
- Expected exit 2017 net debt to flow of funds from operations;
- The objective to manage net debt to funds from operations to be well positioned to create shareholder value and organic growth;
- Expected impact of the MRF program on royalty rates and operations; and
- Expected impact of the Climate Leadership Plan on operating expenses and operations.

References to 2017 drilling locations and future drilling locations do not provide certainty that Bonavista will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves or production. The drilling locations on which Bonavista actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, some of our other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves or production. In addition, references made in the Annual Report to initial production rates, and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. Additionally, such rates may also include recovered "load oil" fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Bonavista. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, Bonavista cautions that the test results should be considered to be preliminary.

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 assumptions and conditions, industry assumptions and 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.

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 condensed 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

March 2, 2017
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, 2016 and December 31, 2015, the consolidated statements of loss and comprehensive 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, 2016 and December 31, 2015, 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

March 2, 2017

Calgary, Canada

BONAVISTA ENERGY CORPORATION
Consolidated Statements of Financial Position

As at December 31	Note	2016	2015
($ thousands)			
Assets			
Current assets			
Cash		**85,977**	—
Accounts receivable		**67,572**	70,380
Prepaid expenses		**4,851**	8,333
Other assets		**12,203**	14,104
Financial instrument commodity contracts	(5)	**5,361**	66,213
Financial instrument contracts	(5)	**2,488**	2,013
		178,452	161,043
Financial instrument commodity contracts	(5)	**3,030**	19,390
Financial instrument contracts	(5)	**2,343**	68,754
Property, plant and equipment	(11)	**2,843,763**	3,064,335
Exploration and evaluation assets	(12)	**144,569**	210,194
Total assets		**3,172,157**	3,523,716
Liabilities and Shareholders' Equity			
Current liabilities			
Accounts payable and accrued liabilities		**117,900**	137,722
Current portion of long-term debt	(14)	**154,334**	34,600
Decommissioning liabilities	(15)	**20,936**	18,559
Dividends payable		**2,493**	2,140
Financial instrument commodity contracts	(5)	**53,837**	2,811
		349,500	195,832
Financial instrument commodity contracts	(5)	**35,981**	2,289
Financial instrument contracts	(5)	**469**	—
Long-term debt	(14)	**775,887**	1,231,031
Other long-term liabilities		**8,816**	10,742
Decommissioning liabilities	(15)	**416,986**	470,342
Deferred income taxes	(16)	**24,274**	65,214
Total liabilities		**1,611,913**	1,975,450
Shareholders' equity	(13)		
Shareholders' capital		**2,837,945**	2,716,011
Exchangeable shares		**93,859**	94,550
Contributed surplus		**53,449**	52,825
Deficit		**(1,425,009)**	(1,315,120)
Total shareholders' equity		**1,560,244**	1,548,266
Commitments	(17)		
Total liabilities and shareholders' equity		**3,172,157**	3,523,716

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 Loss and Comprehensive Loss

For the years ended December 31	Note	2016	2015
($ thousands, except per share amounts)			
Revenues			
Production		**445,434**	599,999
Royalties		**(36,903)**	(54,201)
Production revenues, net of royalties		**408,531**	545,798
Realized gains on financial instrument commodity contracts	(5)	**91,772**	149,153
Unrealized losses on financial instrument commodity contracts	(5)	**(161,930)**	(73,370)
Production revenues, net of royalties and financial instrument commodity contracts		**338,373**	621,581
Expenses			
Operating		**140,592**	190,889
Transportation		**22,566**	36,500
General and administrative		**27,138**	32,495
Share-based compensation	(13)	**8,994**	17,157
Gain on acquisition and disposition of property, plant and equipment	(9,10)	**(66,354)**	(19,946)
Gain on disposition of exploration and evaluation assets	(9,10)	**(23,738)**	(14,534)
Depletion, depreciation, amortization and impairment	(11)	**319,845**	1,168,016
Total expenses		**429,043**	1,410,577
Loss from operating activities		**(90,670)**	(788,996)
Finance costs	(7)	**128,717**	221,342
Finance income	(7)	**(84,460)**	(54,742)
Net finance costs		**44,257**	166,600
Loss before taxes		**(134,927)**	(955,596)
Deferred income tax recovery	(16)	**(38,929)**	(204,051)
Net loss and comprehensive loss		**(95,998)**	(751,545)

Net loss and comprehensive loss per share			
Basic		**(0.40)**	(3.45)
Diluted		**(0.40)**	(3.45)

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, 2014	2,514,006	272,900	57,613	(486,813)	2,357,706
Net loss and comprehensive loss	—	—	—	(751,545)	(751,545)
Conversion of restricted incentive and 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
Net loss and comprehensive loss	**—**	**—**	**—**	**(95,998)**	**(95,998)**
Issuance of equity	**115,001**	**—**	**—**	**—**	**115,001**
Issue costs, net of future tax benefit	**(3,630)**	**—**	**—**	**—**	**(3,630)**
Conversion of restricted incentive and performance incentive awards	**9,200**	**—**	**(9,200)**	**—**	**—**
Tax effect on conversion of restricted incentive and performance incentive awards	**672**	**—**	**—**	**—**	**672**
Share-based compensation expense	**—**	**—**	**8,994**	**—**	**8,994**
Share-based compensation capitalized	**—**	**—**	**830**	**—**	**830**
Exchangeable shares exchanged for common shares	**691**	**(691)**	**—**	**—**	**—**
Dividends declared	**—**	**—**	**—**	**(13,891)**	**(13,891)**
Balance as at December 31, 2016	**2,837,945**	**93,859**	**53,449**	**(1,425,009)**	**1,560,244**

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY CORPORATION
Consolidated Statements of Cash Flows

For the years ended December 31	Note	2016	2015
($ thousands)			
Cash provided by (used in):			
Operating Activities			
Net loss and comprehensive loss		**(95,998)**	(751,545)
Adjustments for:			
Depletion, depreciation, amortization and impairment		**319,845**	1,168,016
Share-based compensation		**8,994**	17,157
Unrealized losses on financial instrument commodity contracts		**161,930**	73,370
Gain on acquisition and disposition of property, plant and equipment		**(66,354)**	(19,946)
Gain on disposition of exploration and evaluation assets		**(23,738)**	(14,534)
Net finance costs		**44,257**	166,600
Deferred income tax recovery		**(38,929)**	(204,051)
Decommissioning expenditures		**(15,309)**	(18,925)
Changes in non-cash working capital items	(8)	**(33,906)**	(9,852)
Cash flow from operating activities		**260,792**	406,290
Financing Activities			
Issuance of equity, net of issue costs		**110,032**	—
Dividends paid		**(13,538)**	(88,885)
Interest paid		**(45,770)**	(48,946)
Proceeds from long-term debt		**—**	66,578
Repayment of long-term debt		**(258,035)**	—
Cash flow used in financing activities		**(207,311)**	(71,253)
Investing Activities			
Exploration and development		**(153,871)**	(313,905)
Property acquisitions	(9)	**(12,166)**	(69,576)
Property dispositions	(10)	**180,071**	100,128
Office equipment		**(604)**	(1,203)
Changes in non-cash working capital items	(8)	**19,066**	(50,481)
Cash flow from (used in) investing activities		**32,496**	(335,037)
Change in cash		**85,977**	—
Cash, beginning of year		**—**	—
Cash, end of year		**85,977**	—

See accompanying notes to the consolidated financial statements.

1. Structure of the Corporation

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 audited consolidated financial statements of the Corporation as at and for the year ended December 31, 2016, are available through our filings on SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

2. 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 3.

These financial statements were authorized for issue by the Corporation's Board of Directors' on March 2, 2017.

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 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 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 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. During the third quarter of 2016, Bonavista disposed of all of the assets in its Southern Alberta CGU. There were no other changes to the composition of Bonavista's CGUs in 2016 or in the comparative 2015 year.

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. Bonavista also assesses its property, plant and equipment to determine if events or circumstances would support the reversal of any previously recorded impairment charges. In this assessment Bonavista considers the facts and circumstances that caused the original impairment charge to be recognized and whether there is a sustained period in which those facts and circumstances changed.

   At December 31, 2016, Bonavista evaluated each of its CGUs for indicators of potential impairment or a reversal of previously recorded impairment charges. There were no indicators of impairment identified and as such no impairment test was performed at December 31, 2016. Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal. If an impairment test had been conducted, management would have evaluated the net present values of each CGU. Key estimates used in the determination of cash flows used to calculate the net present value of a CGU, 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.

3. Significant accounting policies

Basis of consolidation

The consolidated financial statements comprise the financial statements of the Corporation and its subsidiaries as at December 31, 2016. 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 at 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 "Gain (loss) 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 engineering 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.

Exploration and evaluation assets

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.

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.

Employee benefits

Share-based compensation

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

4. Future accounting policies

In April 2016, the IASB issued its final amendments to 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 model features a contract-based five-step analysis of transactions to determine whether, how much and when revenue is to be recognized. New estimates and judgmental thresholds have been introduced, which may affect the amount and timing of the revenue recognized. The new standard applies to contracts with customers and does not apply to insurance contracts, financial instruments or lease contracts. The new standard is to be adopted either retrospectively or using a modified retrospective approach for annual periods beginning on or after January 1, 2018, with early adoption permitted. Bonavista intends to adopt IFRS 9 on a retrospective basis on January 1, 2018. Bonavista is currently in the process of identifying underlying revenue contracts with customers to determine the impact, if any, that the adoption of IFRS 15 will have on its financial statements.

In July 2014, the IASB issued the complete IFRS 9 *Financial Instruments* to replace IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9, 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 new standard is to be adopted retrospectively with some exemptions for annual periods on or after January 1, 2018, with early adoption permitted. Bonavista intends to adopt IFRS 9 on a retrospective basis on January 1, 2018. The extent of the adoption of IFRS 9 on the classification and measurement of the Corporation's financial assets and financial liabilities and related disclosures has not yet been determined. Bonavista does not currently apply hedge accounting to its financial instrument contracts and does not currently intend to apply hedge accounting to any of its financial instrument contracts upon adoption of IFRS 9.

In January 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 new standard is to be adopted either retrospectively or using a modified retrospective approach. 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.

5. Financial risk management

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, natural gas and natural gas liquids 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

At December 31, 2016, Bonavista had entered into the following costless collars to sell oil and natural gas:

Volume		Average Price	Term
Natural gas contracts			
25,000	gjs/d	CDN $3.30 - CDN $3.66 - AECO	January 1, 2017 - December 31, 2017
20,000	gjs/d	CDN $2.60 - CDN $3.00 - AECO	January 1, 2017 - December 31, 2018
5,000	gjs/d	CDN $2.90 - CDN $3.10 - AECO	November 1, 2017 - March 31, 2018
5,000	gjs/d	CDN $2.90 - CDN $3.10 - AECO	November 1, 2018 - March 31, 2019
Oil contracts			
500	bbls/d	CDN $56.00 - $64.25 - WTI	January 1, 2017 - December 31, 2017
500	bbls/d	CDN $57.00 - $65.00 - WTI	July 1, 2017 - December 31, 2017

At December 31, 2016, Bonavista had entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
Natural gas contracts				
40,000	gjs/d	CDN $2.92	Swap - AECO	January 1, 2017 - March 31, 2017
65,000	gjs/d	CDN $3.00	Swap - AECO	January 1, 2017 - December 31, 2017
10,000	gjs/d	CDN $2.60	Swap - AECO	January 1, 2017 - December 31, 2018
50,000	gjs/d	CDN $2.93	Swap - AECO	April 1, 2017 - October 31, 2017(1)
10,000	gjs/d	CDN $3.04	Swap - AECO	October 1, 2017 - December 31, 2017
45,000	gjs/d	CDN $3.09	Swap - AECO	November 1, 2017 - March 31, 2018
40,000	gjs/d	CDN $3.05	Swap - AECO	January 1, 2018 - March 31, 2018
30,000	gjs/d	CDN $2.91	Swap - AECO	January 1, 2018 - December 31, 2018(2)
10,000	gjs/d	CDN $2.70	Swap - AECO	January 1, 2018 - December 31, 2019
5,000	gjs/d	CDN $3.05	Swap - AECO	November 1, 2018 - March 31, 2019
10,550	gjs/d	US $(0.60)	Swap - AECO Basis	January 1, 2017 - December 31, 2018
10,000	gjs/d	CDN $3.23	Sold Call - AECO	January 1, 2017 - December 31, 2017
10,550	gjs/d	US $3.50	Swap - NYMEX	January 1, 2017 - March 31, 2017
26,375	gjs/d	US $3.12	Swap - NYMEX	January 1, 2017 - December 31, 2017
10,550	gjs/d	US $3.04	Swap - NYMEX	April 1, 2017 - October 31, 2017
5,275	gjs/d	US $3.36	Swap - NYMEX	October 1, 2017 - December 31, 2017(6)
10,550	gjs/d	US $2.95	Swap - NYMEX	January 1, 2018 - December 31, 2018
Natural gas liquids contracts				
500	bbls/d	US $27.72	Swap - MTB BT	January 1, 2017 - March 31, 2017(3)
500	bbls/d	US $27.72	Swap - MTB BT	January 1, 2017 - December 31, 2018(3)
500	bbls/d	US $32.76	Swap - MTB BT	January 1, 2017 - December 31, 2019(3)
500	bbls/d	US $31.50	Swap - MTB BT	October 1, 2017 - March 31, 2018(3)
500	bbls/d	US $29.82	Swap - MTB BT	January 1, 2018 - December 31, 2018(3)
500	bbls/d	US $29.40	Swap - MTB BT	April 1, 2018 - December 31, 2018(3)
500	bbls/d	US $30.66	Swap - MTB BT	January 1, 2019 - December 31, 2019(3)
1,000	bbls/d	US 40.0%	Swap - CNWY PN/WTI	January 1, 2017 - March 31, 2017(4)
1,000	bbls/d	US 54.9%	Swap - CNWY PN/WTI	January 1, 2017 - December 31, 2017(4)
1,000	bbls/d	US $23.00	Swap - CNWY PN	January 1, 2017 - December 31, 2017(5)
1,000	bbls/d	US $20.63	Swap - CNWY PN	January 1, 2017 - December 31, 2018(5)
500	bbls/d	US $21.00	Swap - CNWY PN	April 1, 2017 - March 31, 2018(5)
500	bbls/d	US $22.26	Swap - CNWY PN	January 1, 2018 - December 31, 2018(5)
500	bbls/d	US $24.78	Swap - CNWY PN	January 1, 2018 - December 31, 2019(5)
500	bbls/d	US $22.05	Swap - CNWY PN	July 1, 2018 - December 31, 2018(5)
500	bbls/d	US $23.21	Swap - CNWY PN	January 1, 2019 - December 31, 2019(5)
500	bbls/d	US $(2.75)	Swap - WTI-MSW	January 1, 2017 - December 31, 2017

(1) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 5,000 gjs/d on the last trade date of each month for the duration of the contract.
(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) Mont Belvieu 65 nC4/35 iC4 price.
(4) Conway propane price as a percentage of WTI.
(5) Conway propane price.
(6) Includes an extendable feature on 5,275 gjs/d, which at the discretion of the counterparty would continue the term of the contract to December 31, 2018.

Volume		Price	Contract	Term
Oil contracts				
1,000	bbls/d	US $58.25	Swap - WTI	January 1, 2017 - June 30, 2017
1,500	bbls/d	CDN $67.05	Swap - WTI	January 1, 2017 - December 31, 2017
500	bbls/d	US $49.50	Swap - WTI	January 1, 2017 - December 31, 2017
500	bbls/d	CDN $70.10	Swap - WTI	January 1, 2017 - December 31, 2018
500	bbls/d	US $49.00	Swap - WTI	January 1, 2017 - December 31, 2018
500	bbls/d	CDN $71.61	Swap - WTI	January 1, 2017 - December 31, 2019
1,000	bbls/d	CDN $70.20	Swap - WTI	January 1, 2018 - December 31, 2018
500	bbls/d	US $51.00	Swap - WTI	January 1, 2018 - December 31, 2018
1,000	bbls/d	CDN $68.92	Swap - WTI	January 1, 2018 - December 31, 2019
1,000	bbls/d	CDN $70.25	Swap - WTI	January 1, 2019 - December 31, 2019
500	bbls/d	CDN $65.00	Sold Call - WTI	January 1, 2018 - December 31, 2018

Subsequent to December 31, 2016, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
500	bbls/d	US $25.73	Swap - CNWY PN	January 1, 2018 - December 31, 2019(1)
500	bbls/d	US $33.60	Swap - MTB BT	January 1, 2019 - December 31, 2019(2)
10,550	gjs/d	US $(0.77)	Swap - AECO Basis	January 1, 2018 - December 31, 2018
10,550	gjs/d	US $4.00	Sold Call - NYMEX	January 1, 2018 - December 31, 2018

(1) Conway propane price.
(2) Mont Belvieu 65 nC4/35 iC4 price.

At December 31, 2016, Bonavista had entered into the following contracts to purchase electricity:

Volume		Price	Contract	Term
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, 2016 due to a $0.10 change in the price per thousand cubic feet of natural gas - AECO, would have had an impact of approximately $8.7 million on net loss and comprehensive loss (December 31, 2015 - $7.9 million). The change in fair value for those oil financial instrument commodity contracts in place at December 31, 2016 due to a $1.00 change in the price per barrel of oil - WTI would have had an impact of approximately $2.9 million on net loss and comprehensive loss (December 31, 2015 - $1.0 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 loss and comprehensive loss. At December 31, 2016, the fair value recorded on the consolidated statement of financial position for these financial instrument commodity contracts was a net liability of $81.4 million (December 31, 2015 - $80.5 million, net asset) of which a net liability of $48.5 million (December 31, 2015 - $63.4 million, net asset) relates to financial instrument commodity contracts with term dates within one year and a net liability of $33.0 million (December 31, 2015 - $17.1 million, net asset) relates to financial instrument commodity contracts with term dates beyond one year. During the year ended December 31, 2016, a net loss of $70.2 million (December 31, 2015 - $75.8 million, net gain) was recorded on the consolidated statement of loss and comprehensive loss, consisting of a realized gain of $91.8 million (December 31, 2015 - $149.2 million) and an unrealized loss of $161.9 million (December 31, 2015 - $73.4 million).

Physical purchase and sale contracts

At December 31, 2016, Bonavista entered into the following physical contracts to sell natural gas:

Volume		Price	Term
40,000	gjs/d	CDN $3.18	January 1, 2017 - December 31, 2017(1)(2)
15,000	gjs/d	CDN $2.79	April 1, 2017 - October 31, 2017(1)
20,000	gjs/d	CDN $3.00	January 1, 2018 - December 31, 2018(1)
10,000	gjs/d	CDN $2.75	April 1, 2018 - October 31, 2018

(1) 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.
(2) 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 5, 2017	US$ purchased forward	$12,500,000	1.3120
November 2, 2017	US$ purchased forward	$90,000,000	1.3136
November 2, 2020	US$ purchased forward	$160,000,000	1.3049
October 25, 2021	US$ purchased forward	$150,000,000	1.2991
November 2, 2022	US$ purchased forward	$50,000,000	1.3012
May 23, 2023	US$ purchased forward	$40,000,000	1.2974

Holding all other variables constant, a $0.01 change in the CDN$/US$ exchange rate at December 31, 2016 would have had an impact of approximately $3.7 million on net loss and comprehensive loss. The fair value recorded on the consolidated statement of financial position for these financial instrument contracts as at December 31, 2016 was a net asset of $4.4 million (December 31, 2015 - $70.8 million) of which $2.5 million (December 31, 2015 - $2.0 million) relates to financial instrument contracts with term dates within one year and $1.9 million relate to financial instrument contracts with term dates beyond one year (December 31, 2015 - $68.8 million).

For the year ended December 31, 2016, an unrealized loss of $66.4 million was recorded on the consolidated statement of loss and comprehensive loss (December 31, 2015 - $54.7 million unrealized gain). During the year ended December 31, 2016, Bonavista reduced its exposure to foreign exchange fluctuations on outstanding financial instrument contracts by monetizing all positions and re-couponing at the then current market rates. As a result of these transactions a realized foreign exchange gain of $48.1 million was recognized (December 31, 2015 - nil).

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, oil and natural gas marketers and financial intermediaries.

Bonavista's accounts receivable are with oil and natural gas marketers 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 oil and natural gas marketers under normal industry sale and payment terms. Bonavista routinely assesses the financial strength of its counterparties. 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 majority of Bonavista's credit exposure on accounts receivable at December 31, 2016 pertains to accrued sales revenue for December 2016 production volumes. Receivables from oil and natural gas marketers are normally collected by Bonavista on the 25^{th} of the month following production. Receivables with joint operations partners are typically collected within one to three months of the joint operations invoice being issued to the partner. At December 31, 2016 Bonavista’s receivables consisted of $58.6 million of receivables from oil and natural gas marketers of which substantially all has been collected subsequent to December 31, 2016 and $9.0 million from joint operations partners of which $6.5 million has been subsequently collected.

Bonavista routinely monitors the age of its receivables, investigating the issue behind past due amounts and reviewing the creditworthiness and collection history of the counterparty. Bonavista considers all amounts greater than 90 days to be past due. At December 31, 2016 Bonavista has $1.7 million in accounts receivable that is considered to be past due (December 31, 2015 - $3.1 million). Although these amounts have been outstanding for greater than 90 days, they are still deemed to be collectible. As the operator of properties, Bonavista does have the ability in most instances to withhold production from joint operations partners, who are in default of amounts owing.

The carrying amount of cash, accounts receivable and financial instrument contracts represents the maximum credit exposure. Bonavista does not have an allowance for doubtful accounts at December 31, 2016 (December 31, 2015 - nil) and did not provide for any doubtful accounts nor was it required to write-off any receivables during the year ended December 31, 2016 (December 31, 2015 - nil).

Liquidity risk

Liquidity risk is the risk that Bonavista will encounter difficulty in meeting obligations associated with its 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 quarterly 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 six years on foreign exchange contracts. Bonavista’s four year revolving credit facility, as outlined in note 14, 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 14, which range in maturities from June 5, 2017 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 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 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 Bonavista's consolidated statement of financial position for financial instrument contracts was:

	December 31, 2016	December 31, 2015
($ thousands)		
Current assets		
Financial instrument commodity contracts(1)	**5,361**	66,213
Financial instrument contracts(1)	**2,488**	2,013
Long-term assets		
Financial instrument commodity contracts(1)	**3,030**	19,390
Financial instrument contracts(1)	**2,343**	68,754
Current liabilities		
Financial instrument commodity contracts(1)	**(53,837)**	(2,811)
Long-term liabilities		
Financial instrument commodity contracts(1)	**(35,981)**	(2,289)
Financial instrument contracts(1)	**(469)**	—
Net asset (liability)	**(77,065)**	151,270

(1) Level 2

Borrowings under Bonavista's bank credit facility bear interest at a floating market rate and accordingly the fair market value approximates the carrying value. Bonavista had no amounts drawn on the bank credit facility at December 31, 2016 (December 31, 2015 - $272.1 million). The fair market value of Bonavista's senior unsecured notes at December 31, 2016 was approximately $931.9 million (December 31, 2015 - $1.0 billion), compared to a carrying amount of $933.0 million (December 31, 2015 - $995.7 million).

6. Capital Management

Bonavista's objectives when managing capital are to: (i) preserve financial flexibility which will allow it to execute on its growth strategy through expenditures on exploration and development activities; (ii) maintain a strong financial position to support investor, creditor and market confidence; and (iii) deploy capital to provide an appropriate return on investment to its shareholders. Bonavista manages its capital structure and makes adjustments to it in response to changes in economic conditions and the risk characteristics of its underlying light oil, natural gas liquids and natural gas assets. This is accomplished by consistently aligning Bonavista's capital and dividend programs 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, 2016, Bonavista’s ratio of net debt to fourth quarter annualized funds from operations was 2.8 to 1 (December 31, 2015 - 3.4 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 routinely reviewed and 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 considers: 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 14 of the consolidated financial statements.

The following table provides a reconciliation of cash flow from operating activities to funds from operations:

	Three months ended December 31,		Years ended December 31,	
Calculation of Funds from Operations	**2016**	2015	**2016**	2015
($ thousands)				
Cash flow from operating activities	**70,761**	126,735	**260,792**	406,290
Interest expense(1)	**(10,856)**	(12,860)	**(45,616)**	(49,716)
Decommissioning expenditures	**6,637**	3,281	**15,309**	18,925
Changes in non-cash working capital	**12,200**	(21,364)	**33,906**	9,852
Funds from operations (2)	**78,742**	95,792	**264,391**	385,351

(1) Accrued interest expense on Bonavista's long-term debt excluding the amortization of debt issuance costs.

(2) 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:

Net Debt to Funds from Operations	**Year ended December 31, 2016**	Year ended December 31, 2015
($ thousands)		
Long Term Debt	**775,887**	1,231,031
Adjusted working capital deficiency[(1)]	**101,636**	79,632
Total net debt[(2)]	**877,523**	1,310,663
Funds from operations fourth quarter annualized	**314,968**	383,168
Total net debt to funds from operations	**2.8:1**	3.4:1
Funds from operations	**264,391**	385,351
Total net debt to funds from operations	**3.3:1**	3.4:1

(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 a measures with other entities.

7. Finance costs and income

	Year ended December 31, 2016	Year ended December 31, 2015
($ thousands)		
Finance costs		
Accretion of decommissioning liabilities	**8,251**	10,107
Accretion of other liabilities	**1,258**	1,425
Interest on bank debt	**9,309**	10,503
Interest on notes payable	**37,901**	40,745
Realized loss on foreign exchange	**5,491**	—
Unrealized loss on foreign exchange	—	157,850
Unrealized loss on marketable securities	**102**	712
Unrealized loss on financial instrument contracts	**66,405**	—
Total finance costs	**128,717**	221,342
Finance income		
Realized gain on financial instrument contracts	**(48,089)**	—
Unrealized gain on foreign exchange	**(36,371)**	—
Unrealized gain on financial instrument contracts	—	(54,742)
Total finance income	**(84,460)**	(54,742)
Net finance costs	**44,257**	166,600

8. Supplemental cash flow information

($ thousands)	Year ended December 31, 2016	Year ended December 31, 2015
Cash provided by (used for):		
Accounts receivable	**2,706**	32,562
Prepaid expenses	**3,482**	1,192
Other assets	**1,824**	6,081
Accounts payable and accrued liabilities, net of interest accrual	**(22,852)**	(100,168)
	(14,840)	(60,333)
Related to:		
Operating activities	**(33,906)**	(9,852)
Investing activities	**19,066**	(50,481)
	(14,840)	(60,333)

9. Property Acquisitions and Exchanges

On October 13, 2016, Bonavista completed an asset exchange acquiring certain liquids rich natural gas weighted assets within its Deep Basin and West Central core areas, in exchange for non-core assets located in Bonavista's Blueberry area of northeast British Columbia. The amounts recognized on the close of the transaction to the acquired net assets were as follows:

($ thousands)	Amount
Net assets acquired:	
Exploration and evaluation assets	**5,822**
Facilities	**37,557**
Oil and natural gas properties	**108,459**
Decommissioning liabilities	**(10,202)**
Total net assets acquired	**141,636**

The carrying value of the Blueberry area assets disposed of in this asset exchange was $83.9 million, as a result a gain of $57.7 million was recognized on the exchange of these assets. Of the $57.7 million gain recognized on the exchange of the assets, a $32.1 million gain related to property, plant and equipment and a $25.6 million gain related to exploration and evaluation assets. The asset exchange resulted in a net gain due to the fair value of the assets received being greater than the carrying value of the assets disposed, as a result of both Bonavista and its counterparty being motivated to acquire assets that aligned with strategic objectives to enhance development in core areas.

During the year ended December 31, 2016, Bonavista also acquired, through property acquisitions, certain properties and petroleum and natural gas rights within its core areas for $12.2 million (December 31, 2015 - $69.6 million). The acquired assets in both 2016 and 2015 were predominately located in west central Alberta near Edson and Ansell within the Deep Basin core area.

10. Property Dispositions

During the year ended December 31, 2016, Bonavista disposed, through property dispositions, certain non-core assets for a total cash proceeds of $180.1 million, resulting in a gain of $34.3 million on the disposition of property, plant and equipment and a $1.9 million loss on the disposition exploration and evaluation assets. The non-core properties disposed of were predominately comprised of the following transactions which closed in the second half of the year:

- Light oil weighted properties located in Bonavista's Southern Alberta CGU near Lethbridge, Alberta for cash proceeds of $58.3 million. As a result of this transaction Bonavista's Southern Alberta CGU was eliminated.
- Natural gas and natural gas liquids weighted properties located in Bonavista's Central Alberta CGU near the Willesden Green area of Alberta, for cash proceeds of $56.9 million.
- Light oil weighted properties located in Bonavista's South Central Alberta CGU near the Garrington area of Alberta, for cash proceeds of $62.9 million.

During the comparative year ended December 31, 2015, Bonavista disposed of certain non-core petroleum and natural gas rights through asset exchanges and other property dispositions for proceeds of $100.1 million, resulting in a $19.9 million gain on the sale of property, plant and equipment and a $14.5 million gain on the sale of exploration and evaluation assets.

11. Property, plant and equipment

Cost	Oil and natural gas properties	Facilities	Other Assets	Total
($ thousands)				
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
Additions	**152,294**	**4,377**	**604**	**157,275**
Acquisitions	**115,670**	**40,053**	**—**	**155,723**
Transfers from exploration and evaluation assets	**25,868**	**—**	**—**	**25,868**
Changes in decommissioning liabilities	**13,958**	**—**	**—**	**13,958**
Dispositions	**(662,440)**	**(76,848)**	**—**	**(739,288)**
Balance as at December 31, 2016	**4,900,372**	**526,256**	**29,383**	**5,456,011**

Depletion, depreciation, amortization and impairment				
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)
Depletion, depreciation, amortization and impairment	**(294,015)**	**(23,291)**	**(2,539)**	**(319,845)**
Dispositions	**462,450**	**23,287**	**—**	**485,737**
Balance as at December 31, 2016	**(2,474,316)**	**(119,836)**	**(18,096)**	**(2,612,248)**

Carrying amount				
As at December 31, 2016	**2,426,056**	**406,420**	**11,287**	**2,843,763**
As at December 31, 2015	2,612,271	438,842	13,222	3,064,335

For the year ended December 31, 2016, $4.7 million (December 31, 2015 - $7.7 million) of direct general and administrative expenses were capitalized. At December 31, 2016, future development costs of $1,320.0 million were included in Bonavista's depletion calculation (December 31, 2015 - $1,323.9 million).

Impairment Assessment

At December 31, 2016, Bonavista evaluated its property, plant and equipment ("PP&E") assets for indicators of any potential impairment or related reversal. No indicators of impairment were identified as a result of this assessment and as such no impairment test was performed on Bonavista's PP&E assets at December 31, 2016. Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal.

At June 30, 2016, Bonavista had classified certain non-core properties in its Southern Alberta CGU as assets held for sale, as a result, an impairment charge of $56.6 million was recorded using the fair value less cost to sell model based on the estimated consideration to be received according to the purchase and sale agreement. These Southern Alberta assets were disposed of on July 12, 2016. As a result of this disposition, Bonavista disposed of its Southern Alberta CGU in its entirety.

Bonavista conducted impairment tests on all of its CGUs at December 31, 2015, as a result of a significant and sustained decline in forward commodity benchmark prices for oil, natural gas and natural gas liquids. As a result of the impairment tests conducted in 2015, Bonavista recorded an impairment charge to its PP&E assets of $809.0 million. The following table summarizes the estimated recoverable amount and impairment charge by CGU recorded for the year ended December 31, 2015.

		Year ended December 31, 2015	
CGU	**Primary Product Type of Producing Assets**	**Estimated Recoverable Amount**	**Impairment**
($ thousands)			
West Central Area			
Central Alberta CGU	Natural gas and natural gas liquids	1,289,700	364,000
South Central Alberta CGU	Natural gas and natural gas liquids	373,500	105,000
Deep Basin Area			
North Central Alberta CGU	Natural gas	662,500	194,000
Other Area			
British Columbia CGU	Natural gas and natural gas liquids	109,900	83,000
Southern Alberta CGU	Light oil	119,300	15,000
Eastern Alberta CGU	Light oil and natural gas	10,400	48,000
Total		**2,565,300**	**809,000**

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 engineering evaluators; development costs; operating costs; royalty obligations; abandonment costs; and discount rates.

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.

12. Exploration and evaluation assets

Carrying amount	
($ thousands)	
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
Additions	**2,840**
Acquisitions	**10,562**
Dispositions	**(53,159)**
Transfers to property, plant and equipment	**(25,868)**
Balance as at December 31, 2016	**144,569**

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 Assessment

At December 31, 2016, Bonavista determined that no indicators of potential impairment existed with respect to its E&E assets; therefore an impairment test was not performed.

In the comparative year ended December 31, 2015, Bonavista recognized an impairment charge of $3.3 million on E&E assets related to its Southern Alberta CGU where the carrying value exceeded the recoverable amount. For the purpose of the impairment test conducted, the recoverable amounts of E&E assets were determined using internal estimates of the fair value of the undeveloped land and seismic assets based principally on recent and relevant land sales. Bonavista has subsequently disposed of all of the assets in its Southern Alberta CGU.

13. 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, 2016 were $0.06 per share (December 31, 2015 - $0.37 per share). Effective April 1, 2016, Bonavista's dividend policy was changed 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.

The exchangeable shares of Bonavista are exchangeable into common shares based on the exchange ratio, which is adjusted quarterly, 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 at December 31, 2014	203,760	2,514,006
Issued on conversion of exchangeable shares	8,342	178,350
Conversion of restricted incentive and share awards	1,877	—
Share-based compensation	—	23,655
Balance as at December 31, 2015	213,979	2,716,011
Issued for cash	**34,328**	**115,001**
Issue costs, net of future tax benefit	**—**	**(3,630)**
Issued on conversion of exchangeable shares	**34**	**691**
Conversion of restricted incentive and performance incentive awards, net of future tax	**936**	**672**
Share-based compensation	**—**	**9,200**
Balance as at December 31, 2016	**249,277**	**2,837,945**

Exchangeable shares

	Year ended December 31, 2016		Year ended December 31, 2015	
	Exchangeable Shares	**Amount**	Exchangeable Shares	Amount
	(thousands)	($ thousands)	(thousands)	($ thousands)
Balance, beginning of year	3,283	94,550	9,476	272,900
Exchanged for common shares	**(24)**	**(691)**	(6,193)	(178,350)
Balance, end of year	**3,259**	**93,859**	3,283	94,550
Exchange ratio, end of year	1.42923	—	1.39313	—
Common shares issuable on exchange	**4,658**	**93,859**	4,573	94,550

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 (the "Board") 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 stock option, restricted share award, restricted incentive award and performance incentive award plans, collectively the “long-term incentive plans” that entitle officers, directors, employees and certain consultants to receive shares of the Corporation. The restricted incentive award plan (the "RIA plan") and performance incentive award plan (the "PIA plan") are the only active long-term incentive plans under which Bonavista can grant new awards. The number of common shares available for issue under the RIA plan and the PIA plan is limited to 5% of Bonavista's issued and outstanding common shares including common shares issuable on the exchange of outstanding exchangeable shares.

Share-based compensation expense recognized during the year ended December 31, 2016 was $9.0 million (December 31, 2015 - $17.2 million). For the year ended December 31, 2016, $0.8 million of share-based compensation expense was capitalized to property, plant and equipment (December 31, 2015 - $1.7 million). As at December 31, 2016, the balance of contributed surplus attributable to share-based compensation awards was $53.4 million (December 31, 2015 - $52.8 million).

Stock option and common share incentive rights plans

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 did not grant any awards under the stock option plan or common share rights incentive plan during the years ended December 31, 2016 and December 31, 2015.

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 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
Expired, forfeited and cancelled	**(295,821)**	**18.02**
Reduction in exercise price	**—**	**(0.07)**
Balance as at December 31, 2016	**101,468**	**18.07**
Exercisable as at December 31, 2016	**85,468**	**18.47**

At December 31, 2016 there were 0.1 million stock options outstanding (December 31, 2015 - 0.3 million) of which 0.1 million were exercisable (December 31, 2015 - 0.2 million). During the year ended December 31, 2016, all outstanding common share incentive rights expired (December 31, 2015 - 0.1 million).

The following table summarizes information regarding stock options outstanding at December 31, 2016:

	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)
13.80 - 15.76	38,500	1.37	14.38	35,000	14.43
15.77 - 20.73	37,500	2.40	16.45	25,000	16.45
20.74 - 28.84	25,468	0.48	26.01	25,468	26.01
13.80 - 28.84	101,468	1.53	18.07	85,468	18.47

Restricted incentive and restricted share award incentive plans

Bonavista's RIA plan and its legacy restricted share award incentive plan (the "RSA plan") provide compensation to directors, officers, employees and certain consultants based on the notional number of underlying common shares.

Vesting arrangements are within the discretion of the Board, but unless otherwise determined by the Board, all awards granted under the RIA plan (and previously granted under the RSA plan) vest evenly over a period of three years from the date of grant. On the vesting date, the holder will receive, cash or equivalent common shares for each restricted 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 an award granted under the RIA plan (and previously granted under the RSA plan) is assessed on the grant date by 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 a restrictive incentive award or the settlement of the restricted share award 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 awards outstanding under the RIA plan and RSA plan at December 31:

	Restricted Incentive and Restricted Share Awards
Balance as at December 31, 2014	2,762,171
Granted	1,342,537
Reinvestment[1]	231,126
Vested	(1,876,647)
Forfeited	(400,097)
Balance as at December 31, 2015	2,059,090
Granted	**2,017,237**
Reinvestment[1]	**70,356**
Vested	**(883,006)**
Forfeited	**(320,500)**
Balance as at December 31, 2016	**2,943,177**

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

At December 31, 2016 there were 2.9 million restricted incentive awards outstanding (December 31, 2015 - 2.0 million). During the year ended December 31, 2016, all outstanding restricted share awards either vested or were forfeited (December 31, 2015 - 39,000).

Performance incentive award plan

Bonavista's PIA plan was approved by the Board on January 1, 2015 to provide compensation to directors, officers, certain employees and eligible consultants. Awards granted under the PIA plan vest thirty-nine months from the initial date of grant and the number of common shares issued for each award 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 the Board. The number of common shares issued for each performance incentive award ("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 PIA in the form of either cash or common shares, or some combination thereof, however, it is Bonavista's intention to settle the PIA in the form of common shares.

The fair value of an award granted under the PIA plan is determined at the date of grant by using the closing price of common shares, multiplied by the estimated performance multiplier. For the purposes of share-based compensation a performance multiplier of 0.96 has been assumed for those awards granted in 2015 and a performance multiplier of 1 was assumed for those awards granted in 2016. 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 7.32% (December 31, 2015 - 7.05%) for outstanding awards. The estimated weighted average fair value of PIAs granted during the year ended December 31, 2016 was $1.87 per award (December 31, 2015 - $7.26).

The following table summarizes the awards outstanding under the PIA plan at December 31:

	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
Granted	**1,315,219**
Reinvestment[1]	**47,660**
Vested	**(53,258)**
Forfeited	**(322,025)**
Balance as at December 31, 2016	**1,881,519**

(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 loss and comprehensive loss per equivalent share:

	Year ended December 31, 2016	Year ended December 31, 2015
(thousands)		
Common shares	**233,130**	207,564
Exchangeable shares converted at the exchange ratio	**4,676**	10,096
Basic equivalent shares	**237,806**	217,660
Restricted incentive and share awards	**2,433**	1,632
Performance incentive awards	**1,867**	825
Diluted equivalent shares	**242,106**	220,117

14. Long-term debt

	December 31, 2016	December 31, 2015
($ thousands)		
Bank credit facility	**—**	272,056
Senior unsecured notes	**930,221**	993,575
Total long-term debt	**930,221**	1,265,631
Current portion of long-term debt	**154,334**	34,600
Long-term portion of long-term debt	**775,887**	1,231,031

a. Bank credit facility

Bonavista has a $600 million, covenant-based bank credit facility provided by a syndicate of 11 domestic and international banks. The current maturity date of the credit facility is September 10, 2019. 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 facility 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. The average effective interest rate for bank debt outstanding for the year ending December 31, 2016 was approximately 4.2% (December 31, 2015 - 3.8%). At December 31, 2016, Bonavista had no amounts drawn on the bank credit facility providing $600.0 million of unused borrowing capacity (December 31, 2015 - $325.8 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, 2016, 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.

At December 31, 2016, 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%. Of the US$50 million drawn, US$25 million was repaid on June 4, 2016 and the remaining US$25 million matures 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

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, 2016 and 2015. 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

At December 31, 2016, 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.

15. 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 $437.9 million at December 31, 2016 (December 31, 2015 - $488.9 million), based on an estimated total future undiscounted liability of approximately $889.0 million (December 31, 2015 - $1.1 billion). At December 31, 2016 management estimates expenditures required to settle the liability will be made over the next 51 years with the majority of payments being made in years 2048 to 2067. A risk-free rate of approximately 2.3% (December 31, 2015 - 2.2%) based on the Bank of Canada's long-term risk-free bond rate and an inflation rate of 1.8% (December 31, 2015 - 1.8%) were used to calculate the present value of the decommissioning liability at December 31, 2016.

($ thousands)	**Year ended December 31, 2016**	Year ended December 31, 2015
Balance, beginning of year	488,901	497,982
Accretion expense	**8,251**	10,107
Liabilities incurred	**4,810**	6,058
Liabilities acquired	**12,483**	1,828
Liabilities disposed	**(75,172)**	(40,453)
Liabilities settled	**(15,309)**	(18,925)
Revaluation of liabilities acquired(1)	**26,166**	—
Change in estimate(2)	**(12,208)**	32,304
Balance, end of year	**437,922**	488,901
Expected to be incurred within one year	**20,936**	18,559
Expected to be incurred beyond one year	**416,986**	470,342

(1) Relates to the revaluation of acquired decommissioning liabilities using a risk-free discount rate. At the date of acquisition the acquired decommissioning liabilities were recorded at fair value.
(2) Relates to changes in estimated costs, discount rates and anticipated settlement dates of decommissioning liabilities.

16. 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 loss before taxes. The difference results from the following items:

($ thousands)	**Year ended December 31, 2016**	Year ended December 31, 2015
Loss before taxes	**(134,927)**	(955,596)
Current statutory income tax rate	**27.0%**	26.0%
Income tax recovery at current statutory rate	**(36,430)**	(248,455)
Non-deductible (taxable) portion of realized and unrealized foreign exchange	**(1,694)**	13,893
Change in unrecognized deferred tax asset	**(1,694)**	13,893
Non-deductible share-based compensation	**454**	4,271
Effect of tax rate changes and rate variance	**146**	11,281
Other	**289**	1,066
Deferred income tax recovery	**(38,929)**	(204,051)

The tax rate consists of the combined federal and provincial statutory tax rates for Bonavista for the years ended December 31, 2016 and December 31, 2015. The general combined federal and provincial tax rate increased slightly in 2016 due to a decreased weighting in British Columbia and increased weighting in Alberta as a result of the acquisition of liquids rich natural gas assets in Bonavista's Deep Basin and West Central core regions in exchange for non-core assets in Bonavista's Blueberry area of British Columbia.

($ thousands)	**Year ended December 31, 2016**	Year ended December 31, 2015
Deferred income tax liabilities:		
Capital assets in excess of tax value	**346,796**	289,927
Financial instrument contracts	**(21,961)**	21,696
Debt issue costs	**745**	1,151
Deferred income tax assets:		
Decommissioning liabilities	**(118,108)**	(131,759)
Non-capital losses	**(175,784)**	(109,515)
Other liability	**(2,897)**	(3,345)
Issue costs	**(2,165)**	(2,499)
Share-based compensation	**(2,352)**	(442)
Deferred income taxes	**24,274**	65,214

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

($ thousands)	Balance December 31, 2014 (Asset)/Liability	Recognized in profit and loss (Asset)/Liability	Recognized in equity (Asset)/Liability	Balance December 31, 2015 (Asset)/Liability
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

	Balance December 31, 2015 (Asset)/Liability	**Recognized in profit and loss (Asset)/Liability**	**Recognized in equity (Asset)/Liability**	**Balance December 31, 2016 (Asset)/Liability**
($ thousands)				
Property, plant and equipment	289,927	**56,869**	**—**	**346,796**
Decommissioning liabilities	(131,759)	**13,651**	**—**	**(118,108)**
Non-capital losses	(109,515)	**(66,269)**	**—**	**(175,784)**
Issue costs	(2,499)	**1,673**	**(1,339)**	**(2,165)**
Other liability	(3,345)	**448**	**—**	**(2,897)**
Debt issue costs	1,151	**(406)**	**—**	**745**
Financial instrument contracts	21,696	**(43,657)**	**—**	**(21,961)**
Share-based compensation	(442)	**(1,238)**	**(672)**	**(2,352)**
	65,214	**(38,929)**	**(2,011)**	**24,274**

The following is a summary of the estimated tax pools:

	December 31, 2016	December 31, 2015
($ thousands)		
Canadian oil and gas property expense	**520,994**	724,273
Canadian development expense	**580,171**	715,497
Canadian exploration expense	**322,346**	313,758
Undepreciated capital cost	**271,065**	437,363
Non-capital losses	**651,776**	406,362
Other	**8,028**	9,273
Total	**2,354,380**	2,606,526

Non-capital losses carry forward of $651.8 million (December 31, 2015 - $406.4 million) expire in the years 2028 through 2036. Bonavista has capital losses of $5.3 million (December 31, 2015 - $47.9 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, 2016 and 2015 Bonavista paid no tax installments.

17. Commitments

The following table details Bonavista's contractual obligations for long-term debt, lease obligations and other purchase and capital commitments at December 31, 2016:

	Total	2017	2018	2019	2020	2021 and thereafter
($ thousands)						
Long-term debt repayments(1)(3)	930,221	154,334	—	—	214,387	561,500
Interest payments(2)(3)	182,090	36,597	32,084	32,084	30,546	50,779
Office lease(4)	23,127	6,068	6,356	6,760	3,943	—
Drilling service contracts(5)	4,843	1,795	3,048	—	—	—
Transportation expenses	88,070	24,911	20,890	12,728	8,613	20,928
Total contractual obligations	**1,228,351**	**223,705**	**62,378**	**51,572**	**257,489**	**633,207**

(1) Long-term debt repayments include the principal payments due on senior unsecured notes. At December 31, 2016 there were no amounts drawn on the bank credit facility, had amounts been outstanding they would have been required to be paid on September 10, 2019 under the existing terms of the bank credit facility.
(2) Fixed interest payments on senior unsecured notes.
(3) US dollars payments are converted using the exchange rate at December 31, 2016 of $1.3427 CDN/US dollar.
(4) Office lease expires July 31, 2020.
(5) The drilling service contracts are with one service providers extending over a two year term.

18. Supplemental disclosure

a. Income statement presentation

Bonavista's statement of loss is prepared primarily according to 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 loss and comprehensive loss.

($ thousands)	**Year ended December 31, 2016**	Year ended December 31, 2015
Operating	**10,097**	13,529
General and administrative	**21,895**	31,568
Total employee compensation costs	**31,992**	45,097

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 loss and comprehensive loss.

($ thousands)	**Year ended December 31, 2016**	Year ended December 31, 2015
Short-term benefits	**3,701**	3,222
Share-based payments	**2,631**	3,551
	6,332	6,773

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 *(3)*

Robert G. Phillips *(1)(4)*

Ronald J. Poelzer *(5)*

Christopher P. Slubicki *(2)(3)(5)*

(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

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

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 (Canada Branch)
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

Computershare Trust Company of Canada
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BONAVISTA
ENERGY CORPORATION