(TSX:BNP)

FOR IMMEDIATE RELEASE

February 1, 2017

N E W S R E L E A S E

Bonavista Energy Corporation Replaces 131% of 2016 Production with the addition of 32.8 MMboe of Proved Plus Probable Reserves at no net cost

Calgary - Bonavista Energy Corporation ("Bonavista") is pleased to report that our 2016 exploration and development ("E&D") program has resulted in a finding and development ("F&D") cost of $6.97 per barrel of oil equivalent ("boe") on a proved plus probable basis. When combined with our acquisition and divestiture program ("A&D"), finding, development and acquisition ("FD&A") costs were $(0.55) per boe on a proved plus probable basis, in each case including changes in future development costs ("FDC").

2016 Reserves Highlights:

The success we have experienced in the execution of our 2016 capital program continues to reinforce the quality and reliability of the opportunities that exist in our core areas as demonstrated by the highlights listed below:

- Replaced 131% of 2016 production with the addition of 32.8 MMboe of proved plus probable reserves at no cost with net A&D proceeds exceeding our E&D expenditures;
- Added 30.8 MMboe of proved plus probable reserves with our E&D program spending only 58% of our funds from operations to replace 123% of 2016 production;
- Achieved F&D costs of $6.97 per boe on a proved plus probable basis, including changes in FDC, resulting in a recycle ratio of 1.9:1 despite an 18% erosion in realized revenue per boe in 2016 relative to 2015;
- Acquired 38.9 MMboe and divested 37.0 MMboe of proved plus probable reserves resulting in FD&A costs of $(0.55) per boe on a proved plus probable basis, including changes in FDC;
- Reduced our proved developed producing ("PDP") F&D to $9.71 per boe compared to $11.94 per boe in 2015, a 19% improvement; and
- Using the independent reserves evaluation effective December 31, 2016, the net present value of future net revenues discounted at 10% ("PV10") before taxes of our proved plus probable reserves, net of estimated debt of $878 million equates to $7.36 per common share (based on 253.9 million equivalent basic common shares outstanding). With the addition of an internally estimated total land value of $144.6 million, our net asset value would be approximately $7.93 per share.

Operations Update:

For the year ended December 31, 2016, we invested $153.9 million (unaudited) into the development of the key plays in our two core areas drilling 46 (43.1 net) wells resulting in average production of 68,550 boe per day. During the fourth quarter, we drilled 17 (15.9 net) wells generating production of 69,339 boe per day, and currently are producing approximately 71,000 boe per day. Specific operational highlights include the following:

- Reduced 2016 cash costs by 12% to $9.40 per boe when compared to the same period in 2015;
- Reduced our cost to add production through our E&D program by 23% to $13,600 per boe per day when compared to 2015;
- Successfully integrated the assets acquired through the asset exchange which closed in mid-October. Current production from these assets is approximately 6,900 boe per day. We expect to drill 14 wells and generate $44 million of funds from operations on these assets in 2017;
- In December, we closed the previously announced dispositions of 2,900 boe per day for proceeds of $118 million, instrumental in our total corporate debt reduction of $430 million in 2016; and
- Currently we are operating five drilling rigs, three of which are at our Ansell Wilrich development.

2016 Independent Reserves Evaluation:

The evaluation of our reserves was done in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional reserves information as required under NI 51-101 will be included in our Annual Information Form which will be filed on SEDAR on or before March 31, 2017.

Independent reserve evaluators, GLJ Petroleum Consultants Ltd. ("GLJ") evaluated 92% of our total net present value reserves (calculated using a discount rate of 10%) and the balance of our proved plus probable net present value reserves were evaluated internally and reviewed by GLJ in their report dated January 26, 2017 and effective December 31, 2016 (the "GLJ Report").

Reserves Summary:

The following tables summarize our working interest oil, natural gas liquids and natural gas reserves and the net present values ("NPV") of future net revenue for these reserves (before taxes) using forecast prices and costs as set forth in the GLJ Report.

Gross Reserves(1):	Natural Gas(2)	Crude Oil(3)	Natural Gas Liquids	Oil Equivalent Total Reserves	NPV of Future Net Revenue Discounted at 5%	10%	15%
	(MMcf)	(Mbbls)	(Mbbls)	(Mboe)	($000's)	($000's)	($000's)
Proved:							
Proved Producing	632,341	5,526	44,991	155,907	1,630,259	1,331,104	1,128,691
Proved Non-Producing	32,977	305	1,380	7,181	72,053	59,902	51,226
Proved Undeveloped	462,829	2,097	30,860	110,095	820,644	532,739	354,257
Total Proved	1,128,147	7,928	77,231	273,183	2,522,957	1,923,744	1,534,174
Probable	592,890	3,241	38,966	141,022	1,352,861	823,952	557,681
Total Proved plus Probable	1,721,037	11,169	116,197	414,205	3,875,818	2,747,696	2,091,855

(1) Amounts may not add due to rounding.
(2) Includes conventional natural gas, shale natural gas and coal bed methane.
(3) Includes light, medium, heavy and tight oil.

The reserves evaluation was based on GLJ forecast pricing and foreign exchange rates at January 1, 2017 as outlined below. The GLJ January 1, 2017 forecast pricing for natural gas at AECO and West Texas Intermediate ("WTI") oil are CDN$3.46/MMBtu and US$55.00/bbl respectively. This represents a 6% increase in forecast natural gas pricing and a 6% increase in forecast 2017 WTI oil pricing when compared to GLJ's forecast pricing for 2017 at January 1, 2016.

Price Forecast	Edmonton Light Crude Oil	WTI Oil	AECO Natural Gas	Exchange Rate
	(CDN$/bbl)	(US$/bbl)	(CDN$/MMBtu)	(US$/CDN$)
2017	69.33	55.00	3.46	0.750
2018	72.26	59.00	3.10	0.775
2019	75.00	64.00	3.27	0.800
2020	76.36	67.00	3.49	0.825
2021	78.82	71.00	3.67	0.850
2022	82.35	74.00	3.86	0.850
2023	85.88	77.00	4.05	0.850
2024	89.41	80.00	4.16	0.850
2025	92.94	83.00	4.24	0.850
2026	95.61	86.05	4.32	0.850
Thereafter	2.0%/year	2.0%/year	2.0%/year	0.850

Reserves Reconciliation:

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS(1)	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2015	**17,476**	**7,939**	**25,416**	**498**	**153**	**651**
Extensions and Improved Recovery(2)	384	35	419	—	—	—
Technical Revisions	(661)	(520)	(1,181)	(58)	(23)	(81)
Discoveries	—	—	—	—	—	—
Acquisitions	2,299	510	2,809	—	—	—
Dispositions	(10,657)	(4,854)	(15,511)	—	—	—
Economic Factors	—	—	—	—	—	—
Production	(1,331)	—	(1,331)	(23)	—	(23)
December 31, 2016	**7,511**	**3,111**	**10,622**	**417**	**130**	**547**

	NATURAL GAS			NATURAL GAS LIQUIDS		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	(MMcf)	(MMcf)	(MMcf)	(Mbbls)	(Mbbls)	(Mbbls)
December 31, 2015	**1,025,960**	**575,745**	**1,601,705**	**73,256**	**40,221**	**113,477**
Extensions and Improved Recovery(2)	146,110	53,833	199,943	8,768	2,297	11,064
Technical Revisions	(27,892)	(29,257)	(57,149)	(1,163)	(2,034)	(3,197)
Discoveries	—	—	—	—	—	—
Acquisitions	129,307	37,751	167,058	6,543	1,734	8,277
Dispositions	(43,173)	(45,181)	(88,354)	(3,510)	(3,251)	(6,761)
Economic Factors	—	—	—	—	—	—
Production	(102,165)	—	(102,165)	(6,664)	—	(6,664)
December 31, 2016	**1,128,147**	**592,891**	**1,721,037**	**77,231**	**38,966**	**116,197**

	OIL EQUIVALENT		
	Proved	Probable	Proved Plus Probable
	(Mboe)	(Mboe)	(Mboe)
December 31, 2015	**262,224**	**144,270**	**406,494**
Extensions and Improved Recovery(2)	33,503	11,304	44,808
Technical Revisions	(6,531)	(7,453)	(13,984)
Discoveries	—	—	—
Acquisitions	30,393	8,536	38,929
Dispositions	(21,362)	(15,635)	(36,997)
Economic Factors	—	—	—
Production	(25,045)	—	(25,045)
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 as extensions and improved recovery as per NI 51-101.

Reserve Life Index ("RLI"):

Our business plan is to create premium shareholder value through the efficient development of high quality oil and natural gas assets. The profitable growth of our reserves coupled with the sustainable production of these reserves will generate long term returns for our shareholders.

In 2016, our proved plus probable RLI increased by 2% to 14.4 years demonstrating the sustainable balance that exists between our capital program, our reserves additions and our production levels. The production decline characteristics of our asset portfolio influence our RLI. For 2017, GLJ is forecasting a proved developed producing decline rate of 22.6%.

The following table highlights our historical RLI.

Reserve Life Index (Years)[1]	2016	2015	2014	2013	2012
Total Proved	**10.5**	9.7	9.4	9.1	9.6
Total Proved plus Probable	**14.4**	14.1	13.1	13.2	13.5

(1) Calculated based on the amount for the relevant reserves category divided by the production forecast for the applicable year prepared by GLJ.

Future Development Costs:

Changes in forecast FDC occur annually and result from development, acquisition and disposition activities. Future development cost estimates reflect GLJ's best estimate of the costs required to bring the proved and proved plus probable reserves on production. We have 195.2 MMboe reserves assigned to $1,270.2 million of FDC. At a cost of $6.51 per boe, these future reserves generate $998 million of net present value discounted at 10%.

Current year FDC as a ratio of trailing average three year E&D expenditures of $369.1 million is 3.6:1 times, representing prudent and sustainable development forecasts.

The following table sets forth the schedule of FDC required to develop these future reserves (using forecast prices and costs).

Future Development Costs	Total Proved	Total Proved plus Probable
	($ thousands)	($ thousands)
2017	162,286	203,189
2018	307,365	396,539
2019	307,315	384,506
2020	84,814	151,775
2021	50,654	146,460
Remaining	25,680	37,550
Total (Undiscounted)	938,114	1,320,019
Total (Discounted at 10%)	766,015	1,058,928

Reserves Performance Ratios:

The following tables highlight Bonavista's reserves, F&D costs and FD&A costs and the associated recycle ratios. Throughout the year, Bonavista experienced significant improvements in capital efficiencies specifically improving PDP F&D cost by 19% to $9.71 per boe and proved plus probable F&D cost by 4% to $6.97 per boe. Furthermore, we enhanced these results with our acquisition and divestiture strategy resulting in a combined PDP FD&A cost of $(0.86) per boe and proved plus probable FD&A cost of $(0.55) per boe.

Bonavista considers recycle ratio an important measure of profitability. It is measured by dividing the operating netback by the F&D costs per boe for the year. Bonavista delivered an F&D recycle ratio of 1.9:1 for proved plus probable reserves including revisions and changes in future development costs.

	2016	2015	2014
Reserves (Mboe):			
Proved producing	**155,907**	162,072	169,456
Total proved	**273,183**	262,224	275,729
Proved plus probable	**414,205**	406,494	426,767
Capital Expenditures ($ millions):			
E&D	**153.9**	313.9	639.6
Acquisitions, net of dispositions	**(167.9)**	(30.6)	(106.8)
Total capital expenditures	**(14.0)**	283.4	532.8
Operating Netback ($/boe)[1]:			
Current year	**13.44**	16.16	22.60
Three-year weighted average	**17.54**	19.72	20.37

(1) Amounts may not add due to rounding.

Finding and Development Costs:	2016	2015	2014
Proved Producing:			
Change in FDC ($ millions)	**(0.2)**	(0.3)	(4.0)
Reserves additions (MMboe)	**15.8**	26.3	49.5
F&D costs ($/boe)(2)	**9.71**	11.94	12.84
F&D recycle ratio(3)	**1.4**	1.4	1.8
F&D three-year weighted costs ($/boe)(2)	**12.04**	13.57	14.90
F&D recycle ratio three-year weighted average(3)	**1.5**	1.5	1.4
Total Proved:			
Change in FDC ($ millions)	**86.4**	(188.7)	1.3
Reserves additions (MMboe)	**27.0**	20.3	49.5
F&D costs ($/boe)(2)	**8.91**	6.15	12.96
F&D recycle ratio(3)	**1.5**	2.6	1.7
F&D three-year weighted costs ($/boe)(2)	**10.40**	12.21	14.70
F&D recycle ratio three-year weighted average(3)	**1.7**	1.6	1.4
Total Proved plus Probable:			
Change in FDC ($ millions)	**60.9**	(183.5)	(19.1)
Reserves additions (MMboe)	**30.8**	18.0	57.1
F&D costs ($/boe)(2)	**6.97**	7.26	10.86
F&D recycle ratio(3)	**1.9**	2.2	2.1
F&D three-year weighted costs ($/boe)(2)	**9.11**	10.65	12.21
F&D recycle ratio three-year weighted average(3)	**1.9**	1.9	1.7

Finding, Development and Acquisition Expenditures:	2016	2015	2014
Proved Producing:			
Change in FDC ($ millions)	**(2.3)**	4.7	1.1
Reserves additions (MMboe)	**18.9**	21.5	42.8
FD&A costs ($/boe)(2)	**(0.86)**	13.37	12.49
FD&A recycle ratio(3)	**(15.6)**	1.2	1.8
FD&A three-year weighted costs ($/boe)(2)	**9.69**	13.35	13.43
FD&A recycle ratio three-year weighted average(3)	**1.8**	1.5	1.5
Total Proved:			
Change in FDC ($ millions)	**111.6**	(186.0)	45.0
Reserves additions (MMboe)	**36.0**	15.4	47.6
FD&A costs ($/boe)(2)	**2.71**	6.32	12.13
FD&A recycle ratio(3)	**5.0**	2.6	1.9
FD&A three-year weighted costs ($/boe)(2)	**7.81**	12.10	13.05
FD&A recycle ratio three-year weighted average(3)	**2.2**	1.6	1.6
Total Proved plus Probable:			
Change in FDC ($ millions)	**(3.8)**	(198.6)	28.2
Reserves additions (MMboe)	**32.8**	8.6	56.4
FD&A costs ($/boe)(2)	**(0.55)**	9.84	9.95
FD&A recycle ratio(3)	**(24.4)**	1.6	2.3
FD&A three-year weighted costs ($/boe)(2)	**6.42**	10.42	10.71
FD&A recycle ratio three-year weighted average(3)	**2.7**	1.9	1.9

(1) Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, transportation and operating expenditures, calculated on a per boe basis.
(2) Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis.
(3) Recycle ratio is defined as operating netback per boe divided by either F&D or FD&A costs per boe.

Reaffirmed 2017 Guidance:

Our 2017 program is forecasted to provide nine percent production growth and 18% growth in funds from operations, all on a debt and dividend adjusted per share basis. This growth will be provided while maintaining a total payout ratio in the range of 90% to 95% with excess funds used to further improve our financial flexibility. The table below summarizes our reaffirmed 2017 guidance:

	2017F
Payout ratio (%)	90 - 95
E&D capital expenditures ($ millions)	280 - 300
Production (boe/d)	73,500 - 75,500
Funds from operations ($ millions)	300 - 350
Dividends ($ millions)	10
Wells (net)	55 - 60
WTI oil (US$/bbl)	53.00
AECO natural gas (CDN$/gj)	2.85
Exchange rate ($CDN/$US)	0.75

We regularly assess the impact of changes in commodity prices and foreign exchange rates on our business. As such, our 2017 capital budget will remain flexible to accommodate the commodity price volatility.

Hedging & Commodity Marketing:

Bonavista has secured market egress and access for 2017. Bonavista has arranged for firm transportation on the Nova Gas Transmission Ltd. ("NGTL") system north of the James River receipt point ("restricted area") equal to 116% of our forecasted natural gas sales in this area.

Bonavista has also continued to prudently add to our commodity hedge positions. Currently 74% of our forecasted 2017 natural gas production is hedged at an AECO price of $2.94 per gj and we have approximately 10% of our natural gas volumes contracted for delivery to the U.S. Midwest markets. Lastly, we have 75% of oil (oil and condensate) volumes hedged and 49% of our propane volumes hedged for 2017.

General

Bonavista is focused on creating premium shareholder value through the efficient development of high quality oil and natural gas assets.

This news release contains certain financial information that has been derived from our unaudited consolidated financial statements for the year ended 2016.

Oil and Gas Advisories

The reserves estimates contained in this news release represent our gross reserves as at December 31, 2016 and are defined under NI 51-101, as our interest before deduction of royalties and without including any of our royalty interests. **It should not be assumed that the present worth of estimated future net revenues presented in the tables above represents the fair market value of the reserves.** There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

All future net revenues are estimated using forecast prices, arising from the anticipated development and production of our reserves, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs and are stated prior to provision for interest and general and administrative expenses. Future net revenues have been presented on a before tax basis. **Estimated values of future net revenue disclosed herein do not represent fair market value.**

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.

Any references in this news release to short term or initial production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for Bonavista.

This news release contains metrics commonly used in the oil and natural gas industry, such as "recycle ratio", "finding and development costs" or "F&D costs", "F&D recycle ratio", "finding development and acquisition costs" or "FD&A costs", "FD&A recycle ratio" "operating netbacks", "reserve life index" and "net asset value". These oil and gas metrics have been prepared by management and do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this news release to provide readers with additional measures to evaluate Bonavista's performance, however, such measures are not reliable indicators of Bonavista's future performance and future performance may not compare to Bonavista's performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide securityholders with measures to compare Bonavista's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this news release, should not be relied upon for investment or other purposes.

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 reserves revisions during the year on a per boe basis. The aggregate of the E&D costs incurred in the financial year and changes during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this news release because acquisitions and dispositions can have a significant impact on our ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of our cost structure.

Recycle ratio is defined as operating netback per boe divided by either F&D or FD&A costs per boe for the year. F&D recycle ratio is calculated by dividing the netback for the period by the F&D costs per boe for the particular reserve category. FD&A recycle ratio is calculated by dividing the netback for the period by the FD&A costs per boe for the particular reserve category.

Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, transportation and operating expenditures calculated on a per boe basis. Reserve life index is calculated based on the amount for the relevant reserves category divided by the production forecast for the applicable year prepared by GLJ.

Our estimated net asset value is based on the estimated net present value of all future net revenue from our proved plus probable reserves, discounted at 10%, before tax, as estimated by GLJ, at year-end, plus the estimated value of our undeveloped acreage, less long-term debt and net working capital. Common share values in our net asset value per share metric are calculated by including our outstanding common shares and exchangeable shares which are converted into common shares on certain terms and conditions.

The following abbreviations used in this news release have the meanings set forth below:

Bbls	barrels
Mbbls	thousand barrels
Boe	barrels of oil equivalent
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
Mcf	thousand cubic feet
MMcf	million cubic feet
MMBtu	million British Thermal Units
$000's	thousands of dollars

Forward Looking Statements

Corporate information provided herein contains forward-looking information relating to our plans and other aspects of our anticipated future operations, management focus, strategies and business opportunities including statements about our plans to create premium shareholder value, generate long term returns to our shareholders and to profitably grow our reserves coupled with the sustainable production of these reserves, industry conditions, commodity prices and exchange rates, our dividend policy and our financial, operating and production plans and results including our 2017 capital program and allocation thereof, future production, payout ratio, decline rates, funds from operations, future development and other costs, and our market egress and access.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

The forward-looking information is based on certain key expectations and assumptions made by our management, including expectations and assumptions concerning prevailing commodity prices, exchange rates, interest rates, applicable royalty rates and tax laws; future production rates and estimates of operating costs; performance of existing and future wells; reserve volumes; anticipated timing and results of capital expenditures; the success obtained in drilling new wells; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the state of the economy and the exploration and production business; results of operations; performance; business prospects and opportunities; the availability and cost of financing, labour and services; the impact of increasing competition; ability to efficiently integrate assets and employees acquired through acquisitions, ability to market oil and natural gas successfully and our ability to access capital.

Although we believe that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information because Bonavista can give no assurance that they will prove to be correct. Since forward-looking information addresses future events and conditions, by its very nature they involve inherent risks and uncertainties. Our actual results, performance or achievement could differ materially from those expressed in, or implied by, the forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do so, what benefits that we will derive therefrom. Management has included the above summary of assumptions and risks related to forward-looking information provided in this news release in order to provide securityholders with a more complete perspective on our future operations and such information may not be appropriate for other purposes.

Readers are cautioned that the foregoing lists of factors are not exhaustive. Additional information on these and other factors that could affect our operations or financial results are included in reports on file with applicable securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com).

These forward-looking statements are made as of the date of this news release and we disclaim any intent or obligation to update publicly any forward-looking information, whether as a result of new information, future events or results or otherwise, other than as required by applicable securities laws.

This news release also contains future-oriented financial information and financial outlook information (collectively, "FOFI") about our prospective results of operations and funds from operations, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth above. 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 FOFI and forward-looking statements. Bonavista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and FOFI, or if any of them do so, what benefits Bonavista will derive therefrom. Bonavista has included the forward-looking statements and FOFI in this news release in order to provide readers with a more complete perspective on Bonavista's future operations and such information may not be appropriate for other purposes. Bonavista disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

Non-GAAP Measures

This news release contains the term "funds from operations", “operating netbacks”, "payout ratio" and "cash costs" which do not have standardized meanings prescribed by GAAP and therefore may not be comparable with the calculation of similar measures by other companies. Operating netbacks, funds from operations, payout ratios and cash costs are used by Bonavista to analyze financial and operating performance and leverage. Bonavista believes these benchmarks are key measures of profitability and overall sustainability. These terms are commonly used in the oil and gas industry.

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 GAAP. Funds from operations is based on cash flow from operating activities before changes in non-cash working capital, decommissioning expenditures and interest expense. For a reconciliation of funds from operations to cash flow from operating activities, see management's discussion and analysis of our operating and financial results for the three and nine months ended September 30, 2016. Operating netback is calculated using production revenues including realized gains and losses on financial instrument commodity contracts less royalties, transportation and operating expenditures calculated on a per boe basis. Our payout ratio is calculated as dividends paid in cash plus capital expenditures as a percentage of funds from operations. Cash costs are equal to the total of operating, transportation, general and administrative, and financing expenses.

FOR FURTHER INFORMATION CONTACT:

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