BONAVISTA ENERGY CORPORATION

(TSX:BNP)
FOR IMMEDIATE RELEASE
November 2, 2017
NEWS RELEASE

Announces 2017 Third Quarter Results

Calgary - Bonavista Energy Corporation ("Bonavista") is pleased to report to shareholders its financial and operating results for the nine months ended September 30, 2017. Results for the third quarter of 2017 are highlighted by an 11% increase in production to 71,191 boe per day and a 5% decrease in cash costs when compared to the third quarter of 2016, the lowest in over a decade. The unaudited financial statements and notes, as well as management's discussion and analysis, are available on the System for Electronic Document Analysis and Retrieval ("SEDAR") at http://www.sedar.com and on Bonavista's website at www.bonavistaenergy.com.

Highlights

	Three months ended September 30,			Nine months ended September 30,		
	2017	2016	% Change	**2017**	2016	% Change
Financial						
($ thousands, except per share)						
Production revenues	**121,901**	108,206	13 %	**405,814**	303,592	34 %
Funds from operations[1]	**68,459**	66,812	2 %	**215,880**	185,649	16 %
Per share[1] [2]	**0.27**	0.26	4 %	**0.85**	0.80	6 %
Dividends declared	**2,516**	2,491	1 %	**7,522**	11,398	(34)%
Per share	**0.01**	0.01	— %	**0.03**	0.05	(40)%
Net income (loss)	**(1,699)**	(29,386)	94 %	**131,219**	(83,977)	256 %
Per share[3]	**(0.01)**	(0.11)	91 %	**0.51**	(0.35)	246 %
Adjusted net income (loss)[4]	**16,555**	(19,227)	186 %	**45,919**	(38,596)	219 %
Per share[3]	**0.06**	(0.08)	175 %	**0.18**	(0.17)	206 %
Total assets				**3,194,720**	3,227,382	(1)%
Long-term debt, net of working capital				**846,335**	983,200	(14)%
Long-term debt, net of adjusted working capital[5]				**853,616**	986,449	(13)%
Shareholders' equity				**1,698,486**	1,572,181	8 %
Capital expenditures:						
Exploration and development	**77,213**	32,072	141 %	**229,307**	95,297	141 %
Dispositions, net of acquisitions	**2,063**	(55,342)	104 %	**(5,767)**	(50,239)	89 %
Weighted average outstanding equivalent shares: (thousands)[3]						
Basic	**256,177**	253,752	1 %	**255,265**	232,389	10 %
Diluted	**262,805**	258,633	2 %	**261,817**	236,596	11 %
Operating						
(boe conversion – 6:1 basis)						
Production:						
Natural gas (mmcf/day)	**301**	260	16 %	**301**	280	8 %
Natural gas liquids (bbls/day)	**18,639**	17,570	6 %	**18,630**	17,678	5 %
Oil (bbls/day)[6]	**2,350**	3,246	(28)%	**2,399**	3,922	(39)%
Total oil equivalent (boe/day)	**71,191**	64,160	11 %	**71,265**	68,285	4 %
Product prices:[7]						
Natural gas ($/mcf)	**2.84**	3.28	(13)%	**3.02**	3.07	(2)%
Natural gas liquids ($/bbl)	**26.22**	18.88	39 %	**26.88**	17.76	51 %
Oil ($/bbl)[6]	**54.20**	69.53	(22)%	**57.21**	60.07	(5)%
Total oil equivalent ($/boe)	**20.68**	21.97	(6)%	**21.73**	20.62	5 %
Operating expenses ($/boe)	**5.69**	5.31	7 %	**5.59**	5.55	1 %
General and administrative expenses ($/boe)	**0.87**	1.12	(22)%	**0.92**	1.08	(15)%
Cash costs ($/boe)[8]	**8.75**	9.25	(5)%	**8.90**	9.40	(5)%
Operating netback ($/boe)[9]	**12.68**	14.32	(11)%	**13.52**	12.87	5 %

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 (loss) 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 current 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.

	Three months ended			
Share Trading Statistics	**September 30, 2017**	**June 30, 2017**	**March 31, 2017**	**December 31, 2016**
($ per share, except volume)				
High	3.37	3.56	5.22	5.58
Low	2.55	2.22	3.05	3.95
Close	2.98	2.71	3.46	4.81
Average Daily Volume - Shares	617,169	822,516	819,104	877,141

MESSAGE TO SHAREHOLDERS

Despite continued commodity price volatility throughout the third quarter, Bonavista remained focused on those aspects of our business that we can control with an overarching ambition to deliver sustainable value to our shareholders in any commodity price environment.

Relative to the prior year period, production grew 11% to 71,191 boe per day while cash costs were reduced by five percent to $8.75 per boe in the quarter. Capital expenditures were $79.3 million to drill 17 and complete 14 horizontal wells and close four minor acquisition and divestiture transactions.

Throughout the quarter, we curtailed approximately 2,700 boe per day on average due to NOVA Gas Transmission Ltd. ("NGTL") maintenance. Most of our curtailments resulted from an unexpected change in methodology employed by NGTL in the quarter to curtail interruptible delivery service instead of receipt service. This change triggered the erosion of spot AECO natural gas price below $0.50 per gigajoule ("gj") causing voluntary shut-ins. Unfortunately, this AECO volatility has continued into the fourth quarter.

Fortunately, with 80% of our natural gas hedged in the third quarter, we chose to enhance revenue as a marginal buyer of natural gas at these prices, as opposed to a seller. We remain well protected for the balance of the year with 72% of our natural gas production hedged in the fourth quarter.

The natural gas liquids ("NGL") component of our production stream continues to support our revenues. Realized NGL prices improved by 51% to $26.88 per barrel in the first nine months of the year. Improved pricing and five percent growth in NGL volumes resulted in NGL production revenues growing 71% relative to the same period last year. Propane led the way accounting for $31.9 million of our NGL production revenues in the first nine months, compared to $1.6 million during the same period last year.

Our production is currently 73,100 boe per day and we anticipate 2017 annual production to average approximately 72,000 boe per day on forecasted capital expenditures of $275 million. The unexpected NGTL curtailments mentioned above have reduced our annual estimates by approximately 1,000 boe per day however, we have maintained our exit production estimate of approximately 76,000 boe per day, a 10% increase over last year's exit rate.

Operational and financial accomplishments for the third quarter of 2017 include:

- Production averaged 71,191 boe per day representing an 11% increase over the same period last year, notwithstanding approximately 2,700 boe per day of shut-in production due to NGTL curtailments;
- Operating costs of $5.69 per boe led to cash costs of $8.75 per boe, representing an improvement of five percent over the prior year period and the lowest since 2005;

- Executed an E&D capital spending program of $77.2 million drilling 17 and completing 14 wells;
- Reduced long-term debt, net of adjusted working capital by 13% to $853.6 million as compared to the prior year period;
- Generated funds from operations of $68.5 million ($0.27 per share) representing a two percent increase in funds from operations and a four percent increase on a per share basis when compared to the prior year period;
- Elected to reduce the commitment amount under our bank credit facility to $500 million. The $100 million reduction in the commitment results in annual savings of approximately $0.5 million. We currently have undrawn capacity of approximately $410 million; and
- Protected funds from operations with a commodity hedge portfolio consisting of:
    - 72% of our forecasted 2017 fourth quarter natural gas production hedged at an AECO price of $3.32 per mcf and 149 mmcf per day hedged at an AECO price of $3.07 per mcf for 2018;
    - 71% of our forecasted 2017 fourth quarter oil and condensate volumes hedged at CDN$65.35 per bbl WTI and 4,500 bbls per day hedged at CDN$68.12 per bbl for 2018; and
    - 57% of our forecasted 2017 fourth quarter propane volumes hedged at CDN$28.11 per bbl and 3,000 bbls per day hedged at CDN$28.75 per barrel for 2018.

2017 YEAR-TO-DATE CORE AREA HIGHLIGHTS

DEEP BASIN CORE AREA

Our Deep Basin area is characterized by stacked, resource-rich natural gas reservoirs with low cost and high margin operations. Our production base and development plans are supported by having ownership in approximately 266 mmcf per day of operating process capacity, and adequate firm receipt service on NGTL to accommodate all of our budgeted natural gas production for the remainder of 2017 and 2018.

During the first nine months of 2017, we spent $111.8 million on E&D activities drilling 20 (18.5 net) horizontal wells resulting in production rates averaging 26,276 boe per day, representing 42% growth relative to the prior year period. In the last quarter of the year, we forecast E&D spending of $32.1 million to drill eight (6.5 net) wells.

Spirit River (Wilrich, Falher, Notikewin) Natural Gas

We drilled five (5.0 net) Wilrich extended reach horizontal ("ERH") wells at Ansell and one (1.0 net) ERH well at Marlboro. Of these wells, four wells at Ansell have been completed with average initial 30-day raw natural gas rates of 7.3 mmcf per day, similar to our first quarter 2017 wells and 30% greater than the average 30-day rates for our 2016 wells.

Performance of these wells continue to be supported by increased wellbore length, changes in well orientation and completion design. The ERH wells drilled in the first nine months of 2017 are performing at average rates of approximately 725 boe per day per well for the first 180 days of production. This represents a 30% increase over the wells drilled during the same period in 2016. In addition, capital efficiencies have improved 22% to $8,250 per boe per day despite a 10% increase in the cost to drill and complete these wells.

Our 2017 program will conclude with an additional three (3.0 net) ERH Spirit River wells at Ansell in the fourth quarter.

WEST CENTRAL CORE AREA

Our West Central area has a predictable production base that is forecast to generate net operating income of $196 million in 2017. With approximately 760,000 net acres and a drilling inventory of over 715 key play horizontal locations, this area draws its strength from a modest decline rate of 24%, low cost structure, extensive infrastructure and consistent well results.

During the first nine months of 2017, we spent $112.7 million on E&D activities, representing approximately 49% of our corporate E&D spending. This included drilling 29 (28.2 net) wells and has resulted in nine month average daily production of 41,702 boe per day.

For the remainder of the year, we plan to drill two (2.0 net) wells, with E&D spending of $16.0 million inclusive of incremental infrastructure spending. Our development plan is focused in Morningside, Willesden Green and Strachan, where we have enhanced economic performance by drilling ERH wells. We intend to maintain annual production between 41,000 and 42,000 boe per day in 2017 while spending approximately 66% of net operating income.

Glauconite Natural Gas

We drilled two (2.0 net) Glauconite horizontal wells in the third quarter of 2017. One at Hoadley and one at Strachan.

Our Strachan results continue to impress. We drilled one ERH well on the eastern half of our Strachan land base in the third quarter. This well exceeded our expectations with an initial 30-day production rate of 1,100 boe per day including free condensate of 215 barrels per day, which is double that of the Strachan wells drilled in the first half of 2017.

We have over 370 remaining locations to drill in this predictable and reliable resource. This robust inventory will continue to serve as a dependable source to our net operating income for many years to come. We plan to drill two (2.0 net) horizontal wells at Hoadley in the fourth quarter of this year.

Spirit River Falher Natural Gas

We drilled seven (7.0 net) Falher wells at Morningside in the third quarter, five of which were ERH wells and two were conventional horizontal lengths of approximately one mile. Four of the ERH wells are currently on production at rates of approximately 790 boe per day per well for the first 30 days of production.

Our ERH wells continue to enhance the already strong performance at Morningside with our 2017 ERH wells delivering capital efficiencies of $6,100 per boe per day, amongst the best in Western Canada.

We have invested $9 million in infrastructure spending at Morningside in 2017 to accommodate a doubling of production in the fourth quarter relative to the prior year period. The completion of our south Morningside compression facility in October has resulted in current production increasing to 7,000 boe per day.

Over the last 12 months, we have increased our land base by approximately 17,000 acres including approximately 4,500 acres acquired during the third quarter.

Prolific production rates, low well costs of $3.1 million and NGL yields of 100 bbls per mmcf position the Morningside Falher as a top-tier play at current AECO natural gas prices.

STRENGTHS OF BONAVISTA ENERGY CORPORATION

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

Our production and development activity is largely concentrated in two core areas in Alberta which together represent approximately 99% of 2017 net operating income. 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 and economics 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 netbacks that compete favorably in most operating environments. Furthermore, our assets are predominantly operated, providing control over the pace of operations and a direct influence over our operating and capital cost efficiencies.

Our team brings a successful track record of executing reliable development programs with consistency and precision. We continually strive for balance sheet flexibility and remain focused on prudent financial management. Our Board of Directors and management team possess extensive experience in the oil and natural gas business. They have successfully guided our organization through many different economic cycles utilizing a proven strategy underpinned with a set of consistent and reliable operating and financial principles. Directors, management and employees also own approximately nine percent of the equity of Bonavista, aligning our interests with those of external shareholders.

OUTLOOK

AECO daily 5A natural gas prices averaged $1.38 per gj during the third quarter. These industry-numbing prices, frequently fetching no bid on the day, were amongst the most volatile movements in pricing we have witnessed in our 20 years in the business. Maintenance on the NGTL transmission systems causing mandated storage injection restrictions exaggerated weakness in AECO natural gas prices in the third quarter. Clearly, continued pricing at these levels would paralyze much of the natural gas development activity taking place in western Canada today.

Although our industry in Canada continues to face headwinds, structural improvements in supply and demand, specifically in the U.S., are evident. Natural gas storage levels are tracking marginally below the five-year average entering winter, while coal price strength relative to natural gas has enhanced demand of natural gas power generation. Lastly, exports to Mexico and the rest of the world via liquefied natural gas are expected to continue to rise meaningfully in 2018. Notwithstanding these signs, AECO daily 5A natural gas prices have averaged only $0.70 per gj in October, the lowest 5A AECO price we have witnessed for any given month in over 20 years. Ultimately, weather will once again play a critical role in balancing the market in the short-term.

Our funds from operations remains well protected. We have one of the strongest natural gas hedge positions in the industry with 72% of our forecasted fourth quarter 2017 and 47% of forecasted 2018 natural gas production hedged at $3.32 per mcf and $3.07 per mcf respectively.

With AECO futures trading near $2.00 per gj over the next three years, our preliminary approach in 2018 will be to moderate capital spending. At these natural gas prices, value creation via production growth is obscure. Hence, funds from operations in excess of what is required to maintain production will be allocated to strengthen our balance sheet. Notably, we require only $160 to $180 million of capital spending to maintain production between 71,000 and 73,000 boe per day. This is approximately 65% of forecasted funds from operations, allowing for approximately $100 million of excess funds from operations to reduce debt and improve financial flexibility.

Should AECO futures strengthen and approach $2.50 per gj, we have a distinct line-of-sight to profitable growth. In this scenario, we would allocate up to 80% of our excess funds from operations to our top-tier growth opportunities. Maximizing shareholder value is our top priority and we will maintain flexibility and agility in the execution of our capital program in any commodity price environment.

Effective December 7, 2017, Ms. Sue Lee will be stepping down from our Board of Directors. Ms. Lee has served on the Board of Directors since 2013 and has provided valuable guidance and oversight during her tenure with us. We thank her for her service to Bonavista and wish her all the best in the future.

Concurrently, we are pleased to announce the appointment of Ms. Theresa Jang and Mr. David Carey to the Board of Directors, effective today.

Ms. Jang has 27 years of experience in the North American energy infrastructure sector covering: finance, capital markets, investor relations, mergers and acquisitions, accounting, financial reporting and governance. Most recently, Ms. Jang served as Senior Vice President, Finance and Chief Financial Officer of Veresen Inc. During her tenure as CFO of Veresen, she also served as a Board member and Audit Committee Chair at Alliance Pipeline and Aux Sable. Ms. Jang previously held roles of Vice President, Finance and Risk Management and Vice President, Controller at Veresen, and Director, Commercial Analysis and Financial Performance, Gas Transmission East and Controller, TC PipeLines, LP at TransCanada Corp. Ms. Jang holds a Bachelor of Commerce degree from the University of Calgary and is a Chartered Professional Accountant (Chartered Accountant) of Alberta.

Mr. Carey has over 35 years of diverse Canadian and international energy industry experience covering: exploration, production, project evaluations, corporate finance and investor relations in conventional western Canada, oilsands, the Canadian frontiers and international. Mr. Carey retired from his role as Senior Vice President Capital Markets for ARC Resources Ltd. in 2016. In this role, he had responsibility for ARC's investor relations and communications as well as corporate governance activities. Prior to joining ARC Resources Ltd. in 2001, Mr. Carey held the dual roles of Director Investor Relations for Gulf Canada Resources and Vice President and Chief Financial Officer for Athabasca Oil Sands Trust. Mr. Carey holds both a Bachelor of Applied Science (Honours) in Geological Engineering and a Masters in Business Administration from Queen's University. Mr. Carey is a member of the Association of Professional Engineers and Geoscientists of Alberta, the Institute of Corporate Directors and a Fellow of the Canadian Investor Relations Institute.

We are delighted with the new additions to our Board and believe they will add significant value to our organization for many years to come.

We are grateful for the continued support of our shareholders and we thank our employees for consistently finding better ways to advance our business. We firmly believe we are well positioned to succeed through this on-going recovery period in our industry.

FORWARD LOOKING INFORMATION

This document should be read in conjunction with the Management's discussion and analysis ("MD&A") and the unaudited condensed consolidated interim financial statements (the "financial statements") for the three and nine months ended September 30, 2017, together with notes related thereto, as well as in conjunction with the audited consolidated financial statements for the year ended December 31, 2016, together with the notes thereto, for a full understanding of the financial position and results of operations of Bonavista Energy Corporation ("Bonavista" or the "Corporation"). Additional information relating to Bonavista, including the audited consolidated financial statements for the year ended December 31, 2016, are available through SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

Non-GAAP Measures - Throughout this document, 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 (as described below), 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.

Management uses the following terms 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 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. "Adjusted working capital" excludes the current assets and liabilities from financial instrument commodity contracts and decommissioning liabilities. "Debt and dividend adjusted per share basis" is equal to total net debt less interest expense and dividends payable divided by the period end average share price. These converted shares are then added to the weighted average outstanding equivalent shares outstanding.

Oil and Gas Advisories - 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 document 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 interim 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 and 2018 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 current average production volumes and anticipated product mix;
- Expected 2017 and 2018 oil, natural gas and natural gas liquids production volumes;
- Expected realized oil, natural gas and natural gas liquids prices and the differentials resulting from our financial risk management program in 2017 and 2018;
- The benefits of Bonavista's hedging portfolio;
- Expected 2017 and 2018 funds from operations;
- Anticipated rate of return and future payout; and
- The objective to manage net debt to funds from operations to be well positioned to create shareholder value and organic growth.

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 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 natural gas reserves or production. In addition, references made 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 is focused on creating premium shareholder value through the efficient development of high quality oil and natural gas assets.

FOR FURTHER INFORMATION CONTACT:

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