BONAVISTA
ENERGY CORPORATION

(TSX:BNP)
FOR IMMEDIATE RELEASE
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NEWS RELEASE

Announces 2017 First Quarter Results

Calgary - Bonavista Energy Corporation ("Bonavista") is pleased to report to shareholders its financial and operating results for the three months ended March 31, 2017. Results for the first quarter of 2017 are highlighted by a 19% increase in funds from operations and a 5% decrease in cash costs when compared to the first quarter of 2016. Cash costs of $8.98 per boe are the lowest achieved in the past decade showcasing our continued emphasis on cost reductions and efficiency improvements. 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 March 31,		
	2017	2016	% Change
Financial			
($ thousands, except per share)			
Production revenues	**143,182**	104,478	37 %
Funds from operations[1]	**70,851**	59,330	19 %
Per share[1] [2]	**0.28**	0.27	4 %
Dividends declared	**2,503**	6,421	(61)%
Per share	**0.01**	0.03	(67)%
Net income	**88,428**	46,421	90 %
Per share[3]	**0.35**	0.21	67 %
Adjusted net income[4]	**11,431**	23,429	(51)%
Per share[3]	**0.04**	0.11	(64)%
Total assets	**3,242,319**	3,513,479	(8)%
Long-term debt, net of working capital	**906,746**	1,173,430	(23)%
Long-term debt, net of adjusted working capital[5]	**891,737**	1,248,800	(29)%
Shareholders' equity	**1,652,722**	1,591,043	4 %
Capital expenditures:			
Exploration and development	**92,274**	40,622	127 %
Dispositions, net of acquisitions	**(7,540)**	5,038	250 %
Weighted average outstanding equivalent shares: (thousands)[3]			
Basic	**254,586**	218,660	16 %
Diluted	**262,519**	223,723	17 %
Operating			
(boe conversion – 6:1 basis)			
Production:			
Natural gas (mmcf/day)	**293**	301	(3)%
Natural gas liquids (bbls/day)	**18,888**	18,438	2 %
Oil (bbls/day)[6]	**2,560**	4,567	(44)%
Total oil equivalent (boe/day)	**70,281**	73,180	(4)%
Product prices:[7]			
Natural gas ($/mcf)	**3.12**	2.98	5 %
Natural gas liquids ($/bbl)	**26.52**	16.07	65 %
Oil ($/bbl)[6]	**58.50**	53.69	9 %
Total oil equivalent ($/boe)	**22.27**	19.67	13 %
Operating expenses ($/boe)	**5.47**	5.75	(5)%
General and administrative expenses ($/boe)	**0.99**	1.03	(4)%
Cash costs ($/boe)[8]	**8.98**	9.45	(5)%
Operating netback ($/boe)[9]	**13.75**	11.74	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 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	**March 31, 2017**	**December 31, 2016**	**September 30, 2016**	**June 30, 2016**
($ per share, except volume)				
High	5.22	5.58	4.60	3.77
Low	3.05	3.95	3.15	2.23
Close	3.46	4.81	4.22	3.30
Average Daily Volume - Shares	819,104	877,141	1,135,181	1,492,555

MESSAGE TO SHAREHOLDERS

Continued capital and operating cost improvements, combined with enhanced well performance year-to-date has set the stage for profitable per share growth in 2017. With a drilling inventory that is growing in quality, infrastructure and egress solutions in place, and a dependable hedge portfolio, we remain firmly on track to create significant value for our shareholders in 2017 and beyond.

Specific to the quarter, we spent $84.7 million, net of acquisitions and divestitures (“A&D”), drilling 21 wells and growing production from 69,000 boe per day in December 2016 to 74,000 boe per day currently, with approximately 4,000 boe per day waiting to come on-stream. This strong production performance has been driven by our development results in our Spirit River plays which have exceeded our expectations. Our first quarter results in both of our core areas in the Spirit River represent a significant improvement in production and economic performance.

Improved product pricing, specifically natural gas liquids (“NGL”), has been the primary driver to a 26% increase in funds from operations per boe in the first quarter relative to the same period a year ago. A two percent increase in NGL production combined with a 65% increase in realized pricing has led to a 67% increase in revenue (including hedging). As Bonavista has one of the highest NGL compositions relative to total production in our industry, our funds from operations will continue to benefit from the improvement in overall NGL pricing.

Our pragmatic and disciplined approach to managing our cash costs remains key to our success. Operating costs decreased five percent to $5.47 per boe deriving total cash costs of $8.98 per boe, a five percent improvement over the prior year period and the lowest in over a decade. Commodity price support, coupled with an improvement in costs has resulted in an operating netback of $13.75 per boe, a 17% improvement from the prior year period.

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

- Production averaged 70,281 boe per day, precisely aligned with our budget and representing a 68% increase over the first quarter of last year on a debt and dividend adjusted per share basis. Current production is 74,000 boe per day;
- Drilled 21 wells spending $84.7 million including A&D which represents a 13% reduction relative to the budget;
- Generated funds from operations of $70.9 million ($0.28 per share), equivalent to $11.20 per boe representing a 19% increase in funds from operations and a 26% increase on a per boe basis when compared to the prior year period;
- Reduced first quarter operating costs to $5.47 per boe and cash costs to $8.98 per boe, representing reductions of five percent each over the same period in 2016;

- Protected funds from operations through a commodity hedge portfolio resulting in:
    - 74% of our forecasted 2017 natural gas production hedged at an AECO price of $3.30 per mcf and 144 mmcf per day hedged at an AECO price of $3.13 per mcf for 2018;
    - 74% of our forecasted 2017 oil and condensate volumes hedged at CDN$67.69 per bbl WTI and 4,500 bbl per day hedged at CDN$68.85 per bbl for 2018; and
    - 56% of our forecasted 2017 propane volumes hedged at CDN$29.06 per bbl and 3,000 bbl per day hedged at CDN$30.59 per barrel for 2018.

2017 YEAR-TO-DATE CORE AREA HIGHLIGHTS

DEEP BASIN CORE AREA

With 70% of our first quarter exploration and development ("E&D") capital program allocated to the Deep Basin, this core area is on course to grow meaningfully as we pursue numerous drilling opportunities in this prolific area. Our Deep Basin is characterized by stacked, resource-rich natural gas reservoirs with low cost and high margin operations. Furthermore, egress has been secured on the Nova Gas Transmission Ltd. ("NGTL") system for 113% of our budgeted natural gas production for the remainder of 2017 and between 10% to 20% excess transportation secured for 2018.

We support our production base and development plans with access to 266 mmcf per day of operated processing capacity. This control of infrastructure has enabled us to operate at a low cost of $4.21 per boe and an operating margin of 69% in the first quarter leading to competitive development economics in this price environment. First quarter 2017 operating netbacks of $15.39 per boe were 51% greater than the prior year period.

During the first quarter, we spent $64.4 million on E&D activities drilling 12 (10.5 net) horizontal wells supporting average production of 25,518 boe per day, a 29% increase over the same period in 2016. For the remainder of the year, we forecast E&D spending of $90.3 million to drill 19 (16.3 net) wells in the Deep Basin.

Spirit River (Wilrich, Falher, Notikewin) Natural Gas

We drilled 10 (9.8 net) horizontal wells during the first quarter, seven (7.0 net) at Ansell and three (2.8 net) at Marlboro. Well test rates with our extended reach horizontal ("ERH") wells completed in the first quarter at Ansell have been on average 80% higher than our 2016 ERH test results. Notwithstanding restricted production rates, the average initial 30-day raw natural gas rate of 7.8 mmcf per day is 45% greater than the average initial 30-day rate for our 2016 wells. We are excited about this step change in performance and attribute it to a greater understanding of the quality of the reservoir, in addition to innovative drilling and completion techniques including orientation, lateral length, fluid design and stage density.

Drill and complete costs have increased nine percent to $4.4 million in the quarter largely due to inflationary service cost pressures. However, when combined with the forecasted 12-month production performance increase, capital efficiencies improve approximately 20% to $8,400 per boe per day.

Sales production at our Ansell facility has doubled since the start of our winter drilling program in November 2016. Specifically, we are currently selling approximately 85 mmcf per day as a result of the facility expansion completed in March of this year.

For the remainder of the year, we forecast E&D spending of $40.4 million to drill 10 (10.0 net) Ansell Wilrich wells and two (1.5 net) Notikewin wells, all of which will be ERH wells.

WEST CENTRAL CORE AREA

Our West Central core area has a predictable production base that is forecast to generate significant excess funds from operations for many years to come. With approximately 740,000 net acres and a drilling inventory of over 770 key play horizontal locations, this area draws its strength from a relatively low decline rate of 22%, low cost structure, extensive infrastructure and consistent well results. Development economics have strengthened in the first quarter with a 48% improvement in realized NGL prices over the same period last year. This has led to a 77% improvement in the first quarter operating netback of $14.09 per boe.

During the first quarter, we spent $26.1 million on E&D activities, which included drilling nine (8.5 net) horizontal wells, supporting production rates averaging 40,852 boe per day or 58% of corporate production. For the remainder of the year, we plan to drill 24 (23.0 net) wells, with E&D spending of $110.8 million inclusive of incremental infrastructure spending.

Our development is focused in Morningside, Willesden Green and Strachan, where we are enhancing economic performance with longer horizontal wells. This capital program will slightly increase production to between 43,000 and 44,000 boe per day while consuming only 59% of net operating income generated by this core area.

Glauconite Natural Gas

We drilled three (3.0 net) Glauconite horizontal wells, including one (1.0 net) ERH well at Strachan in the first quarter of 2017. We have increased the quality of our Glauconite inventory through on-going A&D initiatives, as evidenced by strong performance of a first quarter well drilled on the swap assets acquired during the fourth quarter of 2016 which outperformed our type curve by approximately 70%.

Low capital costs and an efficient operating cost structure remain key characteristics of our Glauconite play. The average cost per lateral length has also improved while drilling longer length horizontal wells. The average lateral length in the first quarter was 2,155 meters at a cost of $831 per meter, eight percent less than our 2016 costs per lateral meter.

We have over 380 locations identified 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 into the future. For the remainder of 2017, we plan to drill 10 (9.6 net) horizontal wells at Hoadley and three (3.0) horizontal wells at Strachan.

Spirit River Falher Natural Gas

We drilled five (5.0 net) Falher wells in the first quarter including our first ERH well in this play. We have accessed twice as much reservoir with this ERH well in less than 48 hours of incremental drilling time resulting in a material improvement in capital efficiency. We have been able to duplicate the reduced drill time and costs for our second ERH well drilled subsequent to the first quarter. Our Falher inventory in this area currently contains 35% ERH wells.

Our first ERH well tested at over 2,500 boe per day and has been on production for 20 days at a restricted rate of 1,200 boe per day, 35% above our initial projections. With a modest capital cost of $2.6 million to drill and complete this well, payout will occur in approximately 10 months at current strip pricing. The other three wells drilled in the first quarter were completed in the second quarter and came on production in late April.

First quarter production averaged 3,500 boe per day while current production is approximately 5,000 boe per day. We expect to grow average daily production in excess of 7,000 boe per day during the fourth quarter, representing growth of 119% from the fourth quarter of 2016. To accommodate this production growth, we expect to invest $9 million to expand both compression and pipeline infrastructure.

Strong production rates along with high NGL content have significantly improved Morningside ERH economics with payouts of less than a year at current strip pricing. The Morningside Falher play is a top tier development play in western Canada and is a key growth component of our portfolio.

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 forecasted 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 by us, providing control over the pace of operations and a direct influence over our operating and capital cost efficiencies.

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

OUTLOOK

Our industry is currently picking up the pieces from one of the most drastic downturns on record. As demand and supply fundamentals hunt for equilibrium, energy prices will remain volatile.

Tepid North American natural gas consumption this past winter has left natural gas storage levels 15% above the five-year average but 14% lower than 2016. Cooling demand this summer remains a key catalyst and will dictate short-term price fluctuations. Longer term, the demand sentiment in North America has become more constructive, supported by increased exports to Mexico and liquefied natural gas exports to Asia and Europe. Furthermore, local demand will continue to strengthen with the increasing use of natural gas in the development of oilsands and the significant quantities of natural gas required in the conversion of coal to natural gas power generation.

Global oil markets have stabilized, with prices recovering from the historic lows of a year ago. OPEC production curtailments and elevated U.S. drilling activity will be the most significant influences to near-term crude oil prices. Like natural gas, NGL pricing in North America has been influenced by a significant increase in export demand, specifically propane, a product which is abundant in our production and reserve portfolio.

Over the past two years, we have developed a high degree of resilience to the inherent pricing volatility in our industry given our disciplined approach to our commodity hedge portfolio and with our success at improving capital and operating efficiencies. Accordingly, Bonavista is well positioned for value creation through this recovery period. Our 2017 growth plans remain intact drilling between 55 and 65 net wells spending between $280 and $300 million. This investment represents approximately 90% of forecast funds from operations and will generate annual production between 73,500 and 75,500 boe per day. This will translate into annual production growth of seven to 10% and funds from operations growth in excess of 20% at current strip prices. In the unlikely event that AECO natural gas strip prices were to erode by as much as 30% for the balance of the year, our solid hedge portfolio would support funds from operations growth of 15%.

As always, we thank the hard work and dedication of our employees and our shareholders for their continued support. We are pleased with our start to 2017 and look forward to delivering profitable growth in 2017 while further strengthening our financial position.

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 months ended March 31, 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 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 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;
- The benefits of Bonavista's hedging portfolio;
- Expected 2017 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.

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