CALGARY, ALBERTA--(Marketwired - Jul 27, 2017) - Bonavista Energy Corp. (TSX:BNP) ("Bonavista") is pleased to report to shareholders its financial and operating results for the six months ended June 30, 2017. Results for the second quarter of 2017 are highlighted by a 29% increase in funds from operations and a 6% decrease in cash costs when compared to the second quarter of 2016. 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 June 30,			Six months ended June 30,		
	2017	2016	% Change	2017	2016	% Change
Financial						
($ thousands, except per share)						
Production revenues	140,731	90,908	55 %	283,913	195,386	45 %
Funds from operations[1]	76,570	59,507	29 %	147,421	118,837	24 %
Per share[1] [2]	0.30	0.27	11 %	0.58	0.54	7 %
Dividends declared	2,503	2,486	1 %	5,006	8,907	(44)%
Per share	0.01	0.01	- %	0.02	0.04	(50)%
Net income (loss)	44,490	(101,012)	144 %	132,918	(54,591)	343 %
Per share[3]	0.17	(0.45)	138 %	0.52	(0.25)	308 %
Adjusted net income (loss)[4]	17,933	(42,798)	142 %	29,364	(19,369)	252 %
Per share[3]	0.07	(0.19)	137 %	0.12	(0.09)	233 %
Total assets				3,210,082	3,386,563	(5)%
Long-term debt, net of working capital				844,808	1,031,381	(18)%
Long-term debt, net of adjusted working capital[5]				861,784	1,044,721	(18)%
Shareholders' equity				1,699,898	1,601,173	6 %
Capital expenditures:						
Exploration and development	59,820	22,603	165 %	152,094	63,225	141 %
Dispositions, net of acquisitions	(290)	65	546 %	(7,830)	5,103	253 %
Weighted average outstanding equivalent shares: (thousands)[3]						
Basic	254,965	224,473	14 %	254,784	221,576	15 %
Diluted	262,958	229,095	15 %	262,715	226,125	16 %
Operating						
(boe conversion - 6:1 basis)						
Production:						
Natural gas (mmcf/day)	310	279	11 %	302	290	4 %
Natural gas liquids (bbls/day)	18,364	17,027	8 %	18,625	17,732	5 %
Oil (bbls/day)[6]	2,288	3,962	(42)%	2,423	4,264	(43)%
Total oil equivalent (boe/day)	72,313	67,561	7 %	71,303	70,370	1 %
Product prices:[7]						
Natural gas ($/mcf)	3.10	2.95	5 %	3.11	2.97	5 %
Natural gas liquids ($/bbl)	27.91	18.41	52 %	27.21	17.19	58 %
Oil ($/bbl)[6]	58.91	59.60	(1)%	58.70	56.44	4 %
Total oil equivalent ($/boe)	22.24	20.34	9 %	22.26	19.99	11 %
Operating expenses ($/boe)	5.61	5.58	1 %	5.54	5.67	(2)%
General and administrative expenses ($/boe)	0.91	1.09	(17)%	0.95	1.06	(10)%
Cash costs ($/boe)[8]	8.96	9.51	(6)%	8.97	9.48	(5)%
Operating netback ($/boe)[9]	14.14	12.67	12 %	13.95	12.18	15 %

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.

Share Trading Statistics	Three months ended			
	June 30, 2017	March 31, 2017	December 31, 2016	September 30, 2016
($ per share, except volume)				
High	3.56	5.22	5.58	4.60
Low	2.22	3.05	3.95	3.15
Close	2.71	3.46	4.81	4.22
Average Daily Volume - Shares	822,516	819,104	877,141	1,135,181

MESSAGE TO SHAREHOLDERS

Delivering sustainable growth in a narrow margin environment has been our focus through the first half of 2017. Production volumes averaged 71,303 boe per day in the first six months of 2017 generating $147.4 million in funds from operations representing a 24% increase relative to the prior year period.

Growth within funds from operations is largely attributed to our focus on efficiency and peak performance within our most profitable development plays. In the first six months of 2017, our exploration and development ("E&D") program added approximately 20,000 boe per day of production with $152.1 million of capital spending. Relative to 2016, we have experienced an approximate 50% increase in well productivity in the first 90 days of production. Notwithstanding the service cost pressures experienced in the past six months, this performance improvement has resulted in a 26% reduction in our average cost to add production year-to-date.

Complementing our pursuit of efficiency, cash costs have been reduced by five percent to $8.97 per boe and our operating costs by two percent to $5.54 per boe in the first half of 2017 relative to the prior year period. These efforts have derived a two percent improvement in operating margins to 63% creating the opportunity to grow profitably within funds from operations in this commodity price environment.

Improved natural gas liquids ("NGL") prices have supported our development economics year-to-date. Realized NGL prices improved by 58% to $27.21 per boe in the first six months of the year relative to the prior year period. NGL production revenues accounted for 34% of our total production revenue in the first half and have led to a 15% improvement in operating netback to $13.95 per boe. With NGL production consisting of approximately one quarter of our total production, our development economics will continue to benefit from improvements in NGL pricing.

We remain firmly positioned to protect our funds from operations and maximize production revenues with secured and diversified sales and transportation solutions for our products. We have 76% of our natural gas hedged in 2017 and 152 mmcf per day hedged for 2018. Additionally, we have contracted firm transportation on the Nova Gas Transmission Ltd. ("NGTL") system in excess of forecasted production to ensure adequate egress to a trading hub for our natural gas. Lastly, approximately 80 mmcf per day of our 2018 natural gas production is diversified to markets beyond AECO including the U.S. mid-west and Eastern Canada.

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

- Capital spending of $59.5 million net of acquisitions and divestitures ("A&D") was approximately $13 million under budget. We drilled 11 (10.7 net) wells in addition to land and facility expenditures representing 23% of total capital spend. The budget underspend was mainly attributable to delayed drilling and infrastructure projects associated with wet weather conditions;
- Production averaged 72,313 boe per day representing a seven percent increase over the same period last year notwithstanding approximately 2,150 boe per day of turnaround activity at third party facilities and 500 boe per day of ethane rejection. Current production is approximately 73,000 boe per day;
- Reduced long-term debt, net of adjusted working capital by 18% to 861.8 million as compared to the second quarter of 2016;
- Generated funds from operations of $76.6 million ($0.30 per share) representing a 29% increase in funds from operations and an 11% increase on a per share basis when compared to the prior year period;

- Operating costs of $5.61 per boe and a nine percent reduction in transportation costs per boe led to cash costs of $8.96 per boe, a six percent improvement over the same period in 2016. Operating netbacks increased 12% to $14.14 per boe as compared to the prior year period; and
- Protected funds from operations with a commodity hedge portfolio consisting of:
  - 76% of our forecasted 2017 natural gas production hedged at an AECO price of $3.31 per mcf and 152 mmcf per day hedged at an AECO price of $3.15 per mcf for 2018;
  - 73% of our forecasted 2017 oil and condensate volumes hedged at CDN$67.33 per bbl WTI and 4,000 bbls per day hedged at CDN$68.62 per bbl for 2018; and
  - 57% of our forecasted 2017 propane volumes hedged at CDN$28.03 per bbl and 3,000 bbls per day hedged at CDN$28.93 per barrel for 2018.

2017 YEAR-TO-DATE CORE AREA HIGHLIGHTS

DEEP BASIN CORE AREA

Our Deep Basin 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 egress on NGTL to accommodate all of our budgeted natural gas production for the remainder of 2017 and 2018.

We have successfully integrated the Deep Basin assets acquired through the strategic asset exchange completed during the fourth quarter of 2016. We have increased production by 60% to 7,240 boe per day currently, exceeding our original expectations by 1,700 boe per day. In addition, we have recently re-directed approximately 50% of the production acquired in this area to our operated facilities, which will result in a 40% to 50% reduction in operating expenses.

Similar to prior years, spring break-up has curtailed our activity in this core area in the second quarter and one well remains uncompleted. During the first half of 2017, we spent $72.5 million on E&D activities drilling 12 (10.5 net) horizontal wells, completing 15 wells and spending $10 million on facilities. This has resulted in record average quarterly production of 28,349 boe per day. For the remainder of the year, we forecast E&D spending up to $46.5 million to drill up to 15 wells.

Spirit River (Wilrich, Falher, Notikewin) Natural Gas

Our first half extended reach horizontal ("ERH") wells at Ansell are performing at robust rates of approximately 850 boe per day per well on average for the first three months of production, representing a 20% increase over the initial 90-day production period relative to the same period of our first half 2016 program. Capital efficiencies have improved 21% to $8,400 per boe per day despite a nine percent increase in drilling and completion costs.

This performance is primarily attributed to increased wellbore length, a better understanding of the reservoir, changes in well orientation and completion design. Specifically to orientation, the wells were positioned approximately NW-SE to parallel minimum horizontal principle stresses that exist in the reservoir, allowing for more efficient fracture propagation. We continue to gain a better understanding of the reservoir by way of continued permeability mapping using build-up analysis and available drill cuttings. Finally, our completion techniques have also evolved, as we are now utilizing diverter on all of our Ansell Wilrich wells while we refine our proppant placement design.

Specifically, we have drilled two one-mile Wilrich wells in the same spacing unit with a completion design of 40 stages and 20 stages, respectively. Each well was stimulated with 1,000 tonnes of sand. Average initial 60-day flow rates demonstrate an 80% improvement in the 40 stage well with a modest four percent increase in well cost.

The strong performance of our first quarter wells created flow restrictions with our infrastructure across our entire Ansell field. As a result, production volumes through our Ansell facility have been maintained at approximately 80 mmcf per day throughout the entire second quarter. With increased utilization at our facility, coupled with future optimization projects, we anticipate further improvements in operating expenses in the second half of the year.

We have further expanded our Ansell land position acquiring 1,920 contiguous acres to complement our ERH development area.

For the second half of the year, we forecast E&D spending up to $21.2 million to drill up to seven Ansell Wilrich wells.

WEST CENTRAL CORE AREA

Our West Central core area has a predictable production base that is forecast to generate net operating income of $200 million in 2017. With approximately 735,000 net acres and a drilling inventory of over 740 key play horizontal locations, this area draws its strength from a modest decline rate of 22%, low cost structure, extensive infrastructure and consistent well results.

During the second quarter, we spent $50.0 million on E&D activities, representing 85% of our corporate second quarter spending. This included drilling 11 (10.7 net) wells and has resulted in second quarter production of 41,050 boe per day. Ethane recoveries were curtailed unexpectedly by approximately 500 boe per day in May and June due to third party restrictions. We anticipate continued ethane rejections during the second half of the year.

In the first nine months of operations since completing the strategic asset exchange last fall, total acquired production has increased 23% to 2,440 boe per day, and operating expenses have been reduced by 18%.

For the second half of the year, we plan to drill up to 12 wells, with E&D spending of up to $48.9 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 will maintain production at approximately 41,000 boe per day while spending only 63% of net operating income.

Glauconite Natural Gas

We drilled nine (8.7 net) Glauconite horizontal wells, including five (5.0 net) ERH wells (one of which was at Strachan) in the second quarter of 2017.

Optimized capital costs and an efficient development structure remain key characteristics of our Glauconite play. The average cost per lateral length has improved to approximately $800 per meter, 17% less than 2016 as we drill longer wells.

One of the two first half Strachan wells represented the deepest horizontal well we have drilled at 3,285 meters of true vertical depth with 2,440 meters of horizontal length. We continue to see greater development opportunity at Strachan and have added over 40 sections of land in the past 12 months including 10 newly acquired sections through crown land sales during the second quarter.

We have approximately 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 to come. We plan to drill up to three horizontal wells at Hoadley and one horizontal well at Strachan during the second half of the year.

Spirit River Falher Natural Gas

We drilled one (1.0 net) ERH Falher well at Morningside in the second quarter. This well was our second two-mile ERH well in this play and resulted in continued improvements in capital efficiency to $4,500 per boe per day. We are currently producing 5,300 boe per day and remain on track to drill up to eight wells in the second half of 2017. We are investing $9 million into our infrastructure at Morningside to accommodate forecasted production growth in excess of 100% in the fourth quarter relative to the prior year period.

Prolific production rates, well costs of $3.3 million and NGL yields of 100 bbls per mmcf result in strong Morningside ERH economics. Currently, two-mile ERH wells represent approximately 37% of our total drilling inventory at Morningside. 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 98% 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

Natural gas prices were relatively unchanged over the quarter with NYMEX Henry Hub averaging $3.14 per mmbtu, an increase of two percent from the first quarter of 2017 and up 40% year-over-year. North American weather patterns will continue to influence natural gas pricing in the short-term. Unfortunately, the absence of normal heating demand this past winter and scarce cooling demand summer-to-date has placed recent pressure on AECO futures pricing. In a short three months, second half 2017 and 2018 futures pricing has moderated by 19% and 11% respectively. Similarly, with the short-term global supply-demand balance in question for oil and oil products, futures prices for our composite NGL production have decreased by six percent in the second half of this year and seven percent in 2018.

In light of the recent pressure on futures pricing, our approach to capital allocation in the second half of 2017 will remain disciplined and aligned with our commitment to profitable reinvestment. As such, we remain committed to our sustainable growth aspirations while spending within funds from operations. Consequently, we will target capital spending of $280 million and six percent annual production growth of 73,000 boe per day (inclusive of the 500 boe per day ethane rejection forecasted in our West Central core area), representing the lower end of our original guidance range. We forecast exit production of approximately 76,000 boe per day, a 10% increase from the prior year.

We will endure to maximize value for our shareholders by remaining flexible with our capital program while aligning our approach with the ever changing commodity price environment. As such, should commodity price futures strengthen to levels experienced three months ago, we are amply prepared for a $300 million capital spending program and exit production of 80,000 boe per day. Conversely, should natural gas prices erode further, we are prepared to reduce spending in the second half of 2017 to approximately $100 million while maintaining production for the balance of the year and allowing for an incremental $30 million of debt repayment.

We are thankful for the commitment and dedication of our employees and the continued confidence and support of our shareholders. We are well positioned to prevail through this recovery period in our industry and remain committed to providing long-term value to our shareholders.

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 six months ended June 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 Corp. ("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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