BONAVISTA ENERGY CORPORATION

(TSX:BNP)

FOR IMMEDIATE RELEASE

November 1, 2018

NEWS RELEASE

Announces 2018 Third Quarter Results

Calgary - Bonavista Energy Corporation ("Bonavista") is pleased to report to shareholders its financial and operating results for the three and nine months ended September 30, 2018. 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,		
	2018	2017	% Change	**2018**	2017	% Change
Financial						
($ thousands, except per share)						
Production revenues	**131,175**	121,901	8 %	**390,665**	405,814	(4)%
Net income (loss)	**(17,811)**	(1,699)	948 %	**(69,412)**	131,219	(153)%
Per share[1]	**(0.07)**	(0.01)	600 %	**(0.27)**	0.51	(153)%
Cash flow from operating activities	**73,720**	75,268	(2)%	**213,610**	231,104	(8)%
Per share[1]	**0.28**	0.29	(3)%	**0.83**	0.91	(9)%
Adjusted funds flow[2]	**63,688**	68,459	(7)%	**198,520**	215,880	(8)%
Per share[1]	**0.25**	0.27	(7)%	**0.77**	0.85	(9)%
Dividends declared	**2,554**	2,516	2 %	**7,613**	7,522	1 %
Per share	**0.01**	0.01	— %	**0.03**	0.03	— %
Total assets				**2,845,288**	3,194,720	(11)%
Shareholders' equity				**1,471,682**	1,698,486	(13)%
Long-term debt[3]				**760,231**	833,909	(9)%
Net debt[4]				**795,023**	853,616	(7)%
Capital expenditures:						
Exploration and development	**42,317**	77,213	(45)%	**119,320**	229,307	(48)%
Acquisitions, net of dispositions[5]	**(5,821)**	2,063	(382)%	**(4,999)**	(5,767)	(13)%
Corporate[6]	**57**	98	(42)%	**539**	548	(2)%
Weighted average outstanding equivalent shares: (thousands)[1]						
Basic	**259,897**	256,177	1 %	**258,322**	255,265	1 %
Diluted	**266,913**	262,805	2 %	**265,200**	261,817	1 %
Operating						
(boe conversion – 6:1 basis)						
Production:						
Natural gas (mmcf/day)	**287**	301	(5)%	**303**	301	1 %
Natural gas liquids (bbls/day)	**17,868**	18,639	(4)%	**16,771**	18,630	(10)%
Oil (bbls/day)[7]	**2,358**	2,350	— %	**2,259**	2,399	(6)%
Total oil equivalent (boe/day)	**68,036**	71,191	(4)%	**69,540**	71,265	(2)%
Product prices:[8]						
Natural gas ($/mcf)	**2.76**	2.84	(3)%	**2.75**	3.02	(9)%
Natural gas liquids ($/bbl)	**28.90**	26.22	10 %	**30.96**	26.88	15 %
Oil ($/bbl)[7]	**58.84**	54.20	9 %	**60.81**	57.21	6 %
Total oil equivalent ($/boe)	**21.27**	20.68	3 %	**21.41**	21.73	(1)%
Operating expenses ($/boe)	**5.74**	5.69	1 %	**5.72**	5.59	2 %
General and administrative expenses ($/boe)	**0.92**	0.87	6 %	**0.99**	0.92	8 %
Cash costs ($/boe)[9]	**9.46**	8.75	8 %	**9.43**	8.90	6 %
Operating netback ($/boe)[10]	**12.48**	12.68	(2)%	**12.85**	13.52	(5)%

NOTES:

(1) Per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.
(2) Reference should be made to the section entitled "Non-GAAP Measures" in the Management Discussion and Analysis as well as to note 6, "Capital Management", of the financial statements for further disclosure on adjusted funds flow.
(3) Includes the current portion of long-term debt.
(4) Reference should be made to section entitled "Non-GAAP Measures" in the Management Discussion and Analysis as well as to note 6, "Capital Management", of the financial statements for further disclosure on net debt.
(5) Acquisitions, net of disposition capital expenditures refers to expenditures on property acquisitions net of property dispositions.
(6) Corporate capital expenditures refers to expenditures on office equipment.
(7) Oil includes light, medium and heavy oil.
(8) Product prices include realized gains and losses on financial instrument commodity contracts.
(9) Cash costs do not have any standardized meaning under IFRS and therefore it may not be comparable with the calculations of similar measures for other entities. Reference should be made to "Non-GAAP Measures" in the Management Discussion and Analysis for further disclosure on Bonavista's use and calculation of cash costs.
(10) Operating netbacks do not have any standardized meaning under IFRS and therefore it may not be comparable with the calculations of similar measures for other entities. Reference should be made to "Non-GAAP Measures" in the Management Discussion and Analysis for further disclosure on Bonavista's use and calculation of operating netbacks.

	Three months ended			
Share Trading Statistics	**September 30, 2018**	**June 30, 2018**	**March 31, 2018**	**December 31, 2017**
($ per share, except volume)				
High	1.63	1.75	2.32	3.01
Low	1.25	1.13	1.11	1.77
Close	1.49	1.49	1.18	2.25
Average Daily Volume - Shares	527,770	1,086,460	1,070,659	860,422

MESSAGE TO SHAREHOLDERS

Our third quarter results continue to demonstrate our asset quality and capital allocation flexibility in our quest to generate maximum surplus funds flow in a narrow margin price environment. In the first nine months of this year, we have spent approximately 58% of our adjusted funds flow to average 69,540 boe per day of production. We have generated $83.7 million of surplus funds flow exceeding the mid-point of our annual goal of $70 to $90 million in less than nine months. The majority of this surplus has been used to create incremental financial flexibility as we navigate through unprecedented commodity price discounts created by excessive regulatory uncertainty in the western Canadian energy sector.

Continued focus on liquids-rich development and consistent ethane recovery has increased our production weighting of oil and natural gas liquids (“NGL”) to 30% of total production during the quarter, up from 26% in the prior quarter. The NGL component of our production stream continues to support our revenues with realized NGL prices improving 10% over the same period last year.

Significant infrastructure investment at Strachan earlier this year has prompted an active development program over the past four months. Five of the six liquids-rich wells drilled year to-date are currently on production with the sixth anticipated to be on-stream in December. In addition, liquids-rich development success in the Falher at Morningside and the Glauconite at Hoadley has buoyed a 12% increase in corporate oil and natural gas liquids production over the previous quarter.

Throughout and subsequent to the quarter, we have been actively acquiring and divesting of minor assets with numerous counterparties resulting in the net acquisition of approximately 600 boe per day at a cost of approximately $11 million to the end of October. All acquired properties, most of which are scheduled to close in the fourth quarter, complement our core areas with top tier development inventory, much of which will be pursued beginning in 2019.

Notwithstanding recent production curtailments due to stressed pricing at AECO and Station 2, we remain on track to produce between 69,000 and 71,000 boe per day in 2018, as we spend between $155 and $165 million inclusive of net acquisition activity. This will generate between $90 and $100 million of surplus funds flow for 2018, and will result in a total payout ratio of between 60% and 70%.

Operational and financial accomplishments for the third quarter of 2018 include:

- Production averaged 68,036 boe per day for the quarter, outperforming our forecast by two percent and stable in relation to the prior quarter.
- Oil and liquids production increased 12% over second quarter to average 20,226 boe per day, increasing our oil and liquids production weighting to 30% of total production, up four percent from the prior quarter.

- Spent $36.5 million with our capital program, net of acquisitions and divestitures, underspending our forecast by 11% resulting primarily from the delay of minor infrastructure projects due to weather. Exploration and development expenditures amounted to $42.3 million drilling 10 (9.6 net) wells. Five of these wells are on-stream, with the remaining five expected to be on by the end of the year. The five wells are currently producing at a combined rate of approximately 4,325 boe per day.
- Reduced net debt by $31.5 million to $795.0 million, a total reduction of four percent over the prior quarter.
- Realized average natural gas price of $2.76 per mcf for the quarter, representing a 144% premium to the AECO (5A) price. This premium is as a result of having 58% of our natural gas hedged, and 23% of our natural gas physically diversified to markets other than AECO.
- Protected adjusted funds flow over the coming 12 months with approximately 43% of our forecasted winter 2018-2019 natural gas production hedged at a price of $2.44 per gigajoule, and 18% of our summer 2019 natural gas production hedged at a price of $2.02 per gigajoule.

2018 YEAR-TO-DATE CORE AREA HIGHLIGHTS

DEEP BASIN CORE AREA

Our Deep Basin core 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 260 mmcf per day of operated process capacity, and adequate firm receipt service on NOVA Gas Transmission Ltd. ("NGTL") to accommodate all of our budgeted natural gas production for 2018.

During the first nine months of 2018, we produced approximately 28,504 boe per day in this core area, representing eight percent growth relative to the prior year period despite approximately 900 boe per day being curtailed due to NGTL maintenance in the second quarter. Following spring break-up, our Deep Basin development resumed in August with weather conditions limiting activity to only two wells drilled in the third quarter. Overall, we have spent $36 million on exploration and development activities in the first nine months drilling six and completing 11 gross wells. For the remainder of the year, we will spend approximately $16 million to drill four (3.1 net) wells targeting high rate Spirit River natural gas that will feed our low-cost Ansell facility.

Production performance of the wells brought on-stream in the first half of 2018 continue to outperform with production rates on average 20% above forecast. This performance applies to all four plays that we drilled - the Notikewin, Falher, Wilrich and Bluesky. The two Notikewin wells have averaged 6.1 mmcf per day of raw gas over the first seven months of production. The two Falher wells have yielded 20 bbl per mmcf of wellhead condensate over the past 120 days, exceeding our expectations. Our two extended reach horizontal ("ERH") Ansell Wilrich wells have averaged 5.5 mmcf per day over seven months, a 38% improvement over our program in the second half of 2017. Finally, the three Bluesky wells have averaged 3.5 mmcf/d with 12 bbl per mmcf of free condensate with shallow decline rates over the firs 90 days of production. These results substantiate the quality of the 558 drilling locations we have in inventory in the Deep Basin.

WEST CENTRAL CORE AREA

Our West Central core area has a predictable production base with approximately 745,000 net acres and a drilling inventory of approximately 732 horizontal locations within our key plays. This area draws its strength from a low-cost structure, extensive infrastructure and consistent well results.

During the first nine months of 2018, we have spent $80 million on exploration and development activities to drill 17 (16.8 net) liquids rich natural gas wells in the Falher, Notikewin and Glauconite formations. At our northern extension of the Falher play at Morningside, we followed up our first successful step-out well with a second well that is producing at a restricted rate of 9.0 mmcf per day after 30 days on production. Our second Ferrier Notikewin well is performing slightly ahead of expectations at 600 boe per day over the first 90 days including 53 barrels per mmcf of NGLs.

In the third quarter we started four new Glauconite wells at Willesden Green. These wells have averaged 3.5 mmcf per day for the first 30 days of production including 25 barrels per mmcf of wellhead condensate plus an additional 85 per bbl per mmcf of NGLs. We have recently modified our completion design incorporating cemented liners which has reduced our completion costs by 15%. When combined with the enhanced production performance, we are experiencing a 26% improvement in capital efficiency and our expected rate of return has been reduced to under 24 months.

At our Strachan Glauconite play, we have completed our six well drilling program for 2018. Current production at Strachan is approximately 30 mmcf per day, an increase of 82% since June, with one new well remaining to come on-stream in December. Robust NGL production (25 barrels per mmcf wellhead condensate), lower capital costs with modified completion designs, and reduced operating costs ($3.50 per boe) result in some of the most economic development for Bonavista. With approximately 107 Strachan Glauconite drilling locations in our prospect inventory, 80% of which are un-booked, this area has significant potential for value appreciation in the current price environment.

For the remainder of the year, we have one well to drill and three wells to complete.

OUTLOOK

The energy industry is among the largest economic engines driving the Canadian economy. Abundant, reliable, affordable energy is essential to economic growth, improving our standard of living and enhancing our quality of life. Simply put, energy is the lifeblood of our economy and provides for our way of life here in Canada.

Canada is the fifth largest producer of natural gas and sixth largest producer of oil in the world. The size and quality of our resources coupled with our world class environmental and social performance standards should position Canada to be the preferred supplier of cost and carbon competitive natural gas to the global market. Global energy demand is expected to grow 30% by 2040 according to the International Energy Agency's World Energy Outlook. This outlook highlights that oil and natural gas will provide more than half of this energy to the world, with global demand for natural gas forecast to grow 43% by 2040 led by industrial and power sectors.

Unfortunately, the Canadian oil and gas sector is experiencing numerous challenges which place Canada in a difficult position to compete. Large producers and many service providers have reallocated people, equipment, and capital to more competitive jurisdictions. Canadian oil and gas equity raised annually by this sector has vanished to less than $1.0 billion year to date from $10 billion in 2016, sending a strong signal that Canadian energy is struggling to compete.

The critical competitiveness issues are related to market access and regulatory timelines. Our world class resources are land-locked and our pipelines full. Current policies and regulatory burdens have delayed, or in certain cases canceled, the expansion of much-needed infrastructure in Canada required to serve nations experiencing energy poverty, and in dire need of cleaner energy.

Our largest customer over the past five decades has recently become our fiercest competitor. Over the past two years, the US has grown their natural gas export volumes by 85% and oil export volumes by 300% to meet the ever-increasing global demand for energy. Canadian natural resources are being held captive without access to global markets. In western Canada, we currently sell our oil and natural gas to the US at an unimaginable 30% and 48% discount, respectively, while we are importing energy at full price into eastern Canada from foreign suppliers, including the US. This scenario paralyzes economic growth across our nation from sea to sea and should create an urgent and growing imperative across Canada to set policy which efficiently diversifies oil and natural gas markets beyond our existing solitary export market.

We believe economic growth and a clean environment can work together for the common good. Stats Canada reported of the $11.8 billion spent on environmental protection in the most recent year of collected data, that the oil and gas sector accounted for the largest share of expenditures, spending $6.5 billion or 55% of total business environmental protection expenditures. In 2016, GHG emissions in our Canadian energy sector represents only 0.31% of GHG global emissions. The energy industry continues to collaborate and share technology and innovation to reduce GHG emissions intensity and de-couple production growth from emissions growth. With expanded market reach, we believe our country can play a leadership role on the world stage in supporting other countries in their energy demand and climate objectives.

Fundamentally, the commodity price volatility created in Canadian markets by the preceding phenomenon makes it challenging to manage and grow our Canadian natural resources profitably. Despite these challenges, our team at Bonavista has responded in 2018 by adapting our cost structure, focusing on liquids rich natural gas development and enhancing the economic quality of our assets with technology and innovation. This approach has led to nearly $70 million of incremental balance sheet flexibility by spending only 58% of adjusted funds flow year to date to maintain production.

With continued pursuit of these high-quality development opportunities for the balance of this year, we expect to generate a total of $90 to $100 million of surplus funds flow, as we spend $155 to $165 million, inclusive of acquisitions and divestitures, to maintain production and exit the year at approximately 70,000 boe per day.

We are encouraged with the natural gas demand trends we have recently observed in North America. Specifically, US LNG export has been expanding rapidly with capacity forecasted to grow three-fold to nearly 10 bcf per day by this time next year. As well, electrical generation natural gas demand has been at record levels in both Canada and the US for most of this past cooling season which has led to near record low natural gas inventory levels in the North America as we head into the winter heating season.

We are also encouraged with expansion plans underway by TCPL to export an additional 2.5 bcf per day of natural gas out of western Canada by 2021. Given that our natural gas pipelines are full today, wouldn't it be a genuine success to create a regulatory solution which could accelerate the timeline of this expansion by 12 to 24 months? Lastly, the recent final investment decision (FID) announcement by LNG Canada has reinvigorated our long-term fundamental view of Canadian natural gas supply and demand.

While these fundamentals are encouraging, we intend to remain disciplined with our 2019 capital spending plans designed to generate maximum surplus funds flow while maintaining production. We believe that the fundamentals are in place for Canadian natural gas prices to gradually rise over the next decade but not without continued volatility in the short term. With that belief, it is in our best interest to remain pragmatic stewards of capital, innovative with our development programs, and driven by our financial flexibility. As we anticipate structural improvements in Canadian natural gas fundamentals, we will undoubtedly remain agile in our response to these improvements. It is our intent to provide comprehensive guidance with our 2019 capital budget early in 2019.

We would also like to encourage our shareholders to review our inaugural Corporate Responsibility Report released on our website on October 12, 2018. It showcases our success not only within the realm of our environmental, health and safety responsibilities, but also how we have successfully collaborated with many of our stakeholders as we adapt to the ever-evolving business environment. It is our goal at Bonavista to be an industry leader in efficiently and sustainably supplying the world with responsible Canadian energy for years to come. This report demonstrates the many strides we have taken thus far.

We thank our employees for their commitment and dedication and our shareholders for their on-going support. We look forward to remain focused on financial flexibility throughout the remainder of 2018 and value creation through the coming years.

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, 2018, together with notes related thereto, as well as in conjunction with the audited consolidated financial statements for the year ended December 31, 2017, 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, 2017, are available through SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

Non-GAAP Measures - 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. The non-GAAP measures included in this document include:

- "Adjusted funds flow" is based on cash flow from operating activities, excluding changes in non-cash working capital, decommissioning expenditures and interest expense. Bonavista considers adjusted funds flow to be a key measure that provides a more complete understanding of Bonavista's ability to generate cash flow necessary to finance capital expenditures, expenditures on decommissioning obligations and meet its financial obligations. Certain non-cash charges and decommissioning expenditures have been excluded from the calculation of adjusted funds flow, as management believes the timing of collection, payment and incurrence is variable and by excluding them from the calculation management is able to provide a more meaningful measure of Bonavista's cash flow on a continuing basis. More specifically, expenditures on decommissioning liabilities may vary from period to period depending on Bonavista's capital programs and the maturity of its operating areas. The settlement of decommissioning obligations is managed through Bonavista's capital budgeting process which considers its available adjusted funds flow.

- "Cash costs" is equal to the total of operating, transportation, general and administrative, and interest expenses. Cash costs per boe are calculated by dividing cash costs by total production volumes produced in the period. Management uses cash costs in assessing Bonavista's efficiency and overall cost structures. Bonavista's management also believes that cash costs is a common benchmark used by investors when comparing oil and gas companies. Cash costs on a per boe basis assists Bonavista's management and investors in evaluating operating performance on a comparable basis.
- "Net debt" is equal to the bank credit facility and senior unsecured notes, net of working capital, excluding associated assets and liabilities from financial instrument commodity contracts and decommissioning liabilities. Bonavista considers net debt to be a key measure in assessing the liquidity of the Corporation on a comparable basis with prior periods.
- "Operating margin" is equal to production revenues and realized gains and losses on financial instrument commodity contracts less royalties, operating expenses and transportation expenses; 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 operating netback and operating margin metrics. Operating margin is used by management to show operating performance at both a disaggregated (core area) and aggregated level (corporate). This metric is used by management to illustrate the proportion of Bonavista's revenue available for expenditures after operating expenditures are considered. Bonavista's management also believes that operating margin is a common benchmark used by investors when comparing oil and gas companies.
- "Operating netback" is equal to production revenues and realized gains and losses on financial instrument commodity contracts, less royalties, operating and transportation expenses. Operating netback per boe is calculated by dividing operating netback by total production sold in the period. Management believes that operating netback is a key industry benchmark and a measure of performance for Bonavista that provides investors with information that is commonly used by other crude oil and natural gas producers. Operating netback on a per boe basis assists Bonavista's management and investors in evaluating operating performance on a comparable basis.
- "Payout ratio" is equal to net capital expenditures and dividends declared, divided by adjusted funds flow. The payout ratio is a key cash flow measure that is used by management to determine the sustainability of Bonavista's dividend and capital expenditure program.
- "Surplus funds flow" is equal to adjusted fund flow less capital expenditures. Bonavista considers surplus funds flow to be a key cash flow measure in analyzing the sustainability of Bonavista's dividend program and ability to meet financial obligations after executing on its net capital expenditures program.

Reference should be made to the MD&A for additional disclosure on these non-GAAP measures. In addition, with respect to adjusted funds flow and net debt, readers should also refer to note 6, "Capital Management" of the financial statements.

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.

Bonavista has included disclosure pertaining to future drilling locations within its Message to Shareholders. In accordance with NI 51-101, drilling locations can be categorized as: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that we will drill all identified drilling locations and if drilled there is no certainty that such locations will result in additional oil and natural gas reserves or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, some of our other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves or production.

For Deep Basin, West Central and Strachan Glauconite locations all locations with booked reserves were prepared by an independent qualified reserve evaluator ("QRE") and sourced from the reserve evaluator’s year-end 2017 reserve report. The remaining locations were determined by an internal QRE and sourced from our internal document that summarizes geological and economic parameters for identified locations. The Deep Basin area has an estimated 558 gross locations comprised of 102 gross locations with proved undeveloped reserves, 61 gross locations with probable undeveloped reserves and 395 gross locations that would be classified as resources other than reserves ("ROTR") - contingent resources. The West Central area has an estimated 732 gross locations comprised of 182 gross locations with proved undeveloped reserves, 72 gross locations with probable undeveloped reserves and 478 gross locations that would be classified as ROTR - contingent resources. The Strachan Glauconite area has an estimated 107 gross locations comprised of 10 gross locations with proved undeveloped reserves, 11 gross locations with probable undeveloped reserves and 86 gross locations that would be classified as ROTR - contingent resources.

Any references made in this document to initial production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. While encouraging, readers are cautioned not to place undue reference on such rates when calculating Bonavista's aggregate production.

Forward-Looking Statements *-* Bonavista's news release and Message to Shareholders contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words “anticipate”, “expect”, “project”, “plan”, “estimate”, “budget”, “will”, “strategy”, “ongoing”, “potential”, “believe”, “continue" and similar expressions are intended to identify forward-looking information. Any "financial outlook" in this document, as defined by applicable securities laws, has been approved by the management of Bonavista. Such financial outlook 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 2018 including drilling, and exploration and development plans;
- Expectation of the number of wells to be brought on-steam by the end of 2018;
- Expected 2018 total and current average production volumes and anticipated product mix;
- Expected 2018 natural gas, natural gas liquids, and oil production volumes;
- Expected completion cost savings and improved rate of return as a result of design changes in completion projects;
- Expected realized natural gas, natural gas liquids and oil prices and the differentials resulting from our financial risk management program in 2018;
- Expectation that firm receipt service arrangements will accommodate budgeted natural gas production for 2018;
- The benefits of Bonavista's hedging portfolio;
- Anticipated rate of return and future payout ratio;
- The expected close of property acquisitions in the fourth quarter of 2018;
- The objective to manage net debt to adjusted funds flow to be well positioned to create shareholder value;
- The expectation of the modified retrospective adoption of IFRS 16, *Leases;* and
- The expectation of Global energy demand for 2040 and US LNG export capacity.

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, liabilities inherent in oil and gas operations, future well production rates, the performance of existing and future wells, the success of Bonavista's exploration and development activities, future operating costs, access to markets, 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 natural gas, natural gas liquids and oil assets in the Western Canadian Sedimentary Basin.

FOR FURTHER INFORMATION CONTACT:

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