(TSX:BNP)
FOR IMMEDIATE RELEASE
February 14, 2019
N E W S R E L E A S E

Announces 2018 Fourth Quarter and Year End Results and 2019 Capital Plan

Calgary - Bonavista Energy Corporation ("Bonavista") is pleased to report to shareholders its financial and operating results for the three months and year ended December 31, 2018. The 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.

MESSAGE TO SHAREHOLDERS

"In 2018, we celebrated our 21st anniversary of efficient operations in the Western Canadian Sedimentary Basin, a basin abundant with world-class natural resources being developed under stringent environmental regulations and social standards that are second to none." stated Jason Skehar, president and CEO of Bonavista.

Notwithstanding the headwinds our sector faced in 2018, the future net revenue attributable to our gross proved plus probable reserves ("2P") discounted at a rate of 10%, before deducting future income tax expenses ("BTNPV10")[2], increased seven percent to $2.64 billion. The increase in reserve value was achieved while spending less than 50% of our adjusted funds flow[1] on our capital program to drill for and acquire reserves. After adjusting our 2P BTNPV10 for net debt[1] as at December 31, 2018, our net asset value per share increased 10% to $6.92 per share.

Despite natural gas prices at AECO weakening to $1.44 per GJ for the year, a 22-year low, we generated $63.3 million of adjusted funds flow[1] in excess of net capital expenditures[1] required to maintain production at 68,000 boe per day in the final three quarters of the year. In 2018, $60.0 million was directed towards debt repayment which contributed to reducing net debt[1] by $475 million over the past three years, significantly enhancing financial flexibility for the future.

We strategically allocated our exploration and development ("E&D") capital to our highest quality development projects, focusing on opportunities rich in natural gas liquids ("NGLs"). This allowed us to increase our production weighting of natural gas liquids and oil to 31% in the fourth quarter, up from 29% in the prior year period. Furthermore, we replaced 306% of our 2018 NGL production with 2P NGL reserves.

Our operating, financial and reserve highlights in 2018 prove the quality, resilience and sustainability of our asset base. The strategy deployed in 2018 has undoubtedly enhanced our ability to create shareholder value in the future.

2018 FOURTH QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- Maintained quarter-over-quarter production at 68,011 boe per day, despite approximately 1,600 boe per day of unscheduled production curtailments, largely due to third party processing interruptions and volatile AECO natural gas prices caused by maintenance on the Nova Gas Transmission ("NGTL") system;
- Acquired approximately 13,500 prospective net acres and 500 boe per day of liquids rich production offsetting our operations in the Hoadley Glauconite trend near Willesden Green;
- Drilled five gross (4.3 net) wells in the fourth quarter;
- Increased NGL production to 19,131 per day, a seven percent increase over the prior quarter and the highest quarterly volume in 2018;
- Reduced cash costs[1] to $9.27 per boe, a two percent improvement over prior quarter and the lowest quarterly cost in 2018;
- Directed 30% of our exploration and development expenditures to support capital, primarily related to crown land acquisitions and infrastructure improvements, that will add value beyond 2018; and
- Hedged an incremental 95 mmcf per day for 2019 and contracted an incremental 20 mmcf per day to sales markets beyond AECO effective April 1, 2019.

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".
(2) The net present value of future net revenue attributable to Bonavista's gross proved plus probable reserves at December 31, 2018, before deducting future income tax expenses, calculated at a discount rate of 10% using the forecast price and cost assumptions of GLJ Petroleum Consultants Ltd. ("GLJ"). Reference should be made to the section entitled "Oil and Gas Advisories".
(3) Basic per share calculations includes exchangeable shares which are convertible into common shares on certain terms and conditions.

	Three Months Ended			Year Ended	
	September 30, 2018	**December 31, 2018**	December 31, 2017	**December 31, 2018**	December 31, 2017
Financial					
($ thousands, except per boe and per share amounts)					
Production revenues	131,175	**124,302**	147,188	**514,967**	553,002
Net income (loss)	(17,811)	**81,227**	(159,149)	**11,815**	(27,930)
Per share[2]	(0.07)	**0.31**	(0.62)	**0.05**	(0.11)
Cash flow from operating activities	73,720	**77,581**	94,515	**291,191**	325,619
Per share[2]	0.28	**0.30**	0.37	**1.13**	1.27
Adjusted funds flow[1]	63,688	**61,075**	86,108	**259,595**	301,988
Per share[2]	0.25	**0.23**	0.33	**1.00**	1.18
Dividends declared	2,554	**2,555**	2,518	**10,168**	10,040
Per share	0.01	**0.01**	0.01	**0.04**	0.04
Total assets	2,845,288	**2,923,709**	2,959,470	**2,923,709**	2,959,470
Shareholders' equity	1,471,682	**1,552,184**	1,539,461	**1,552,184**	1,539,461
Long-term debt	760,231	**801,625**	800,544	**801,625**	800,544
Net debt[1]	795,023	**835,905**	840,173	**835,905**	840,173
Capital expenditures:					
Exploration and development	42,317	**45,172**	59,722	**164,492**	289,029
Acquisitions, net of dispositions[3]	(5,821)	**11,037**	(2,074)	**6,038**	(7,841)
Corporate	57	**221**	9	**760**	557
Weighted average outstanding equivalent shares: (thousands)[1]					
Basic	259,897	**260,047**	256,386	**258,781**	255,559
Diluted	266,913	**267,135**	262,980	**265,671**	262,046
Operating					
(boe conversion – 6:1 basis)					
Production:					
Natural gas (MMcf/day)	287	**281**	318	**297**	306
Natural gas liquids (bbls/day)	17,868	**19,131**	19,284	**17,366**	18,794
Oil (bbls/day)[4]	2,358	**2,108**	2,463	**2,221**	2,415
Total oil equivalent (boe/day)	68,036	**68,011**	74,799	**69,154**	72,156
Product prices:[5]					
Natural gas ($/mcf)	2.76	**2.91**	3.14	**2.78**	3.05
Natural gas liquids ($/bbl)	28.90	**24.99**	28.47	**29.30**	27.29
Oil ($/bbl)[4]	58.84	**28.47**	59.49	**53.07**	57.80
Total oil equivalent ($/boe)	21.27	**19.91**	22.65	**21.04**	21.97
Operating expenses ($/boe)	5.74	**5.66**	5.57	**5.70**	5.59
Transportation expense ($/boe)	1.42	**1.37**	1.10	**1.34**	0.94
General and administrative expenses ($/boe)	0.92	**0.87**	0.99	**0.96**	0.94
Cash costs ($/boe)[1]	9.46	**9.27**	8.96	**9.39**	8.92
Operating netback ($/boe)[1]	12.48	**11.99**	14.81	**12.64**	13.85

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".
(2) Basic per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.
(3) Expenditures on property acquisitions, net of property dispositions.
(4) Oil includes light, medium and heavy oil.
(5) Product prices include realized gains and losses on financial instrument commodity contracts.

	Three months ended			
Share Trading Statistics	**December 31, 2018**	**September 30, 2018**	**June 30, 2018**	**March 31, 2018**
($ per share, except volume)				
High	1.60	1.63	1.75	2.32
Low	1.01	1.25	1.13	1.11
Close	1.20	1.49	1.49	1.18
Average Daily Volume - Shares	817,647	527,770	1,086,460	1,070,659

Q4 2018 Capital Program

Net capital expenditures[1] increased to $56.4 million in the quarter from $36.6 million in the third quarter of 2018. Exploration and development expenditures modestly increased from $42.3 million to $45.2 million. Notably, in the quarter we spent $9.8 million on crown land acquisitions and infrastructure for future value creation. We drilled 4.3 net wells in the quarter as compared to 9.6 net wells in the third quarter of 2018. We also executed numerous acquisitions and minor dispositions, resulting in a net expenditure of $11.0 million in the fourth quarter.

Q4 2018 Production

Production volumes for the quarter averaged 68,011 boe per day consisting of 281 mmcf per day of natural gas, 19,131 boe per day of natural gas liquids and 2,108 bbl per day of oil. Our 2018 fourth quarter production volumes of 68,011 boe per day was similar to our previous quarter's production of 68,036 boe per day despite the impact of approximately 1,600 boe per day of unscheduled production curtailments due to low natural gas pricing caused by maintenance on the NGTL system, third party processing constraints, and ethane rejection. Our 2018 focus of allocating capital to liquids rich projects has resulted in our oil and natural gas liquids ratio moving up modestly to 31% of total production as compared to the prior quarter of 30%.

Q4 2018 Production Revenue, Marketing and Risk Management

Production revenues for the fourth quarter of 2018, inclusive of realized gains on financial instrument commodity contracts, was $124.6 million or $19.91 per boe, which was $8.6 million lower or six percent lower than the previous quarter production revenues, inclusive of realized gains on financial instrument commodity contracts, of $133.1 million or $21.27 per boe. This variance was largely due to the impact of wide oil differentials causing a 31% erosion (inclusive of realized gains on financial instrument commodity contracts) in oil and condensate revenues. Realized pricing on natural gas volumes in the quarter was $2.91 per mcf, an 88% premium over the average AECO daily spot price for the quarter of $1.55 per mcf. Hedging contributed to a $0.33 per mcf premium to our realized natural gas price, a $3.88 per boe discount to our realized NGL price and a $7.74 per boe discount to our realized oil price.

Q4 2018 Operating and Transportation Expenses

Operating expenses in the quarter were $5.66 per boe, an improvement over the prior quarter of $5.74 per boe. The Strachan cost structure continues to impress where we recorded operating expenses on a per boe basis of $3.93 on production volumes averaging 5,500 boe per day in the fourth quarter representing approximately six percent of our corporate operating expenses.

Transportation expenses in the prior quarter of 2018 were $1.42 per boe relative to the $1.37 per boe in the fourth quarter of 2018 with both oil and liquids transportation expenses on a per barrel basis lower by 25% and 22% respectively. In the fourth quarter of 2018 we also experienced unutilized firm natural gas transportation expenses of $888,000, or $0.03 per mcf, as compared to $933,000 in the previous quarter.

Q4 2018 General, Administrative and Interest Expenses

General and administrative expenses decreased six percent in the current quarter to $5.4 million as compared to $5.8 million in the third quarter of 2018, due to lower salaries and benefits recorded in the quarter.

Interest expenses of $8.6 million recorded in the fourth quarter of 2018 were similar to the third quarter of 2018. We exited the fourth quarter of 2018 with lower average borrowings on our bank facility which reduced our interest expense by $210,000. These savings were offset, however, by the increase in the CAD$/US$ foreign exchange rate as interest on our notes are largely denominated in US dollars.

Q4 2018 Cash Flow from Operating Activities and Adjusted Funds Flow

Cash flow from operating activities in the fourth quarter of 2018 of $77.6 million increased modestly from the third quarter of 2018 at $73.7 million, despite production revenues, inclusive of gains on financial commodity instrument contracts, declining to $19.91 per boe from $21.27 per boe. Improvements in operating, transportation and general and administrative expenses contributed to improving cash flow from operations quarter over quarter. Adjusted funds flow[1] for the quarter was $61.1 million as compared to $63.7 million in the previous quarter for similar reasons as discussed above in addition to changes in working capital and lower decommissioning expenditures.

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

2018 YEAR IN REVIEW

The quality and predictability of our asset portfolio, combined with the discipline and determination of our technical teams to innovate and deploy enhanced development practices has resulted in five percent growth in 2P reserves and a seven percent increase in our 2P BTNPV10.

2018 RESERVE HIGHLIGHTS

- Replaced 184% of 2018 production with the addition of 46.3 mmboe of 2P reserve additions. This was accomplished while spending less than 50% of our adjusted funds flow[(1)], with $128.1 million spent to drill 24.9 net wells and acquire reserves;
- Replaced 306% of 2018 NGL production with the addition of 19.4 mmboe of 2P NGL reserve additions. Our corporate 2P NGL ratio increased eight percent or 5 barrels per mmcf of sales gas resulting in 11% growth in 2P NGL reserves;
- 2P FD&A costs improved 24% to $5.72 per boe including changes in future development capital ("FDC") resulting in a 2P FD&A recycle ratio of 2.2:1;
- Proved producing FD&A improved year-over-year by 14% to $9.12 per boe including FDC with positive technical revisions of 1.1 mmboe, related primarily to NGL reserves, with continued well performance improvements;
- 2P F&D costs improved 11% to $6.78 per boe including FDC, a reserve addition cost last experienced by Bonavista 18 years ago;
- Continued innovation and the application of new technology has resulted in our average undeveloped well cost remaining at $3.5 million per well despite an increase of extended reach horizontal wells in our undeveloped inventory. This coupled with a five percent increase in the average 2P reserves per well has resulted in a decrease in our average forecasted undeveloped F&D costs of $5.98 per boe; and
- Notwithstanding a significant reduction in GLJ's price forecasts from year-end 2017 to 2018, our 2P BTNPV10 reserves increased seven percent to $2,635.1 million as at December 31, 2018. When adjusted for net debt[(1)] and undeveloped land value, our net asset value is $7.40 per share, an increase of eight percent or $0.58 per share compared to last year.

2018 Independent Reserves Evaluation

We retained the independent qualified reserve evaluators, GLJ Petroleum Consultants Ltd. (**"GLJ"**) to evaluate 100% of our total light crude oil and medium crude oil (combined), heavy crude oil, conventional natural gas and natural gas liquids reserves. The reserves data set forth below is based upon the evaluation by GLJ with an effective date of December 31, 2018 as contained in the reserve report of GLJ dated February 13, 2019 (the **"2018 GLJ Reserve Report"**). The 2018 GLJ Reserve Report used GLJ's forecast price and cost assumptions. The effective date of the forecast prices used in the 2018 GLJ Reserve Report was January 1, 2019.

The reserves data set forth below also contains information regarding our 2017 reserve estimates which were based upon the evaluation by GLJ with an effective date of December 31, 2017 as contained in the reserve report of GLJ dated January 31, 2018 (the **"2017 GLJ Reserve Report"**). The 2017 GLJ Reserve Report used GLJ's forecast price and cost assumptions. The effective date of the forecast prices used in the 2017 GLJ Reserve Report was January 1, 2018.

Reserves Summary

The following table summarizes the estimates of our gross reserves at December 31, 2018 and December 31, 2017, using the forecast price and cost assumptions in effect at the applicable reserve evaluation date:

Reserve Category[(1)]	December 31, 2018	December 31, 2017	% Change
(Mboe)			
Proved:			
Developed Producing	**148,613**	154,819	(4)%
Developed Non-Producing	**9,057**	7,658	18 %
Undeveloped	**136,506**	112,531	21 %
Total Proved	**294,177**	275,008	7 %
Probable	**164,704**	162,735	1 %
Total Proved Plus Probable	**458,881**	437,743	5 %

Note:

(1) Amounts may not add due to rounding.

Net Present Value of Future Net Revenue

The following table highlights the net present value of future net revenue attributable to our reserves at December 31, 2018, before deducting future income tax expense using GLJ's forecast price and cost assumptions:

Reserve Category[1]	Net Present Value of Future Net Revenue as of December 31, 2018 before Income Taxes Discounted at					Unit Value before Income Taxes Discounted at[2]	
(%/year)	0%	5%	10%	15%	20%	10%	10%
	($000s)	($000s)	($000s)	($000s)	($000s)	($/boe)	($/Mcfe)
Proved:							
Developed Producing	1,877,187	1,450,682	1,173,200	984,874	850,805	8.92	1.49
Developed Non-Producing	60,569	48,397	38,785	31,530	26,031	4.68	0.78
Undeveloped	1,530,027	895,144	550,337	347,392	219,458	4.47	0.74
Total Proved	3,467,783	2,394,224	1,762,322	1,363,796	1,096,293	6.70	1.12
Probable	2,699,380	1,427,813	872,810	589,205	425,208	5.97	0.99
Total Proved Plus Probable	6,167,163	3,822,037	2,635,132	1,953,001	1,521,501	6.44	1.07

Notes:

(1) Amounts may not add due to rounding.
(2) Unit values are based on net reserves.

GLJ commodity price forecasts have been reduced significantly for most products relative to a year ago. For 2019, AECO natural gas prices have eroded 27% while the Edmonton light oil prices have been reduced by 10%. Similarly, for 2019 the ethane, propane, butane and pentane price has been reduced by 28%, 31%, 56% and 9% respectively. Bonavista's net present value of future net revenue attributable to Bonavista's 2P BTNPV10 increased seven percent to $2,635.1 million with a reserve life index of 16.6 years. The 505 2P undeveloped locations included in the 2018 GLJ Reserve Report have a BTNPV10 of $1.12 billion.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of our gross reserves between December 31, 2018 and December 31, 2017 and using the forecast price and cost assumptions in effect at the applicable reserve evaluation date in the 2018 GLJ Reserve Report and 2017 GLJ Reserve Report:

	RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS[1]				
	Light and Medium Crude (Mbbls)	Heavy Oil (Mbbls)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)	Oil Equivalent (Mboe)
GROSS TOTAL PROVED					
December 31, 2017	5,962	400	1,155,012	76,145	275,008
Extensions and Improved Recovery[2]	158	—	131,242	9,617	31,649
Technical Revisions[3]	(49)	(141)	1,430	1,552	1,601
Discoveries	—	—	—	—	—
Acquisitions	81	—	50,534	5,244	13,748
Dispositions	(990)	—	(4,181)	(232)	(1,919)
Economic Factors	132	1	(4,110)	(177)	(729)
Production	(790)	(15)	(108,339)	(6,321)	(25,182)
December 31, 2018	**4,504**	**245**	**1,221,589**	**85,829**	**294,177**

RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE FORECAST PRICES AND COSTS[1]					
	Light and Medium Crude (Mbbls)	Heavy Oil (Mbbls)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)	Oil Equivalent (Mboe)
GROSS TOTAL PROBABLE					
December 31, 2017	2,773	132	722,009	39,495	162,735
Extensions and Improved Recovery[2]	41	—	12,502	2,488	4,613
Technical Revisions[3]	(315)	(34)	(27,016)	(517)	(5,369)
Discoveries	—	—	—	—	—
Acquisitions	31	—	14,749	1,574	4,063
Dispositions	(265)	—	(1,425)	(82)	(584)
Economic Factors	(145)	—	(2,947)	(115)	(752)
Production	—	—	—	—	—
December 31, 2018	2,120	98	717,873	42,842	164,704
GROSS TOTAL PROVED PLUS PROBABLE					
December 31, 2017	8,735	532	1,877,021	115,640	437,743
Extensions and Improved Recovery[2]	198	—	143,744	12,105	36,261
Technical Revisions[3]	(364)	(175)	(25,586)	1,035	(3,769)
Discoveries	—	—	—	—	—
Acquisitions	112	—	65,283	6,818	17,811
Dispositions	(1,255)	—	(5,605)	(314)	(2,503)
Economic Factors	(13)	1	(7,057)	(293)	(1,481)
Production	(790)	(15)	(108,339)	(6,321)	(25,182)
December 31, 2018	6,623	343	1,939,462	128,671	458,881

Notes:

(1) Amounts may not add due to rounding.
(2) Infill drilling, improved recovery and extensions have been grouped as extensions and improved recovery as per NI 51-101.
(3) Includes product transfer types to reconcile the opening balance for changes in classification between light medium crude and heavy oil.

On average, 2018 2P reserve performance exceeded the projections in the 2017 GLJ Reserve Report as suggested by the following performance improvements:

- Added 1.1 mmboe of proved developed producing reserves due to positive technical revisions;
- Experienced a base production decline rate of 25% for 2018 versus the GLJ forecast at 28%;
- NGL production as a percentage of total production was similar to GLJ at 25% despite experiencing significant ethane curtailment at numerous times throughout 2018; and
- 2018 operating netback[1] of $12.64 per boe was approximately seven percent higher than that forecasted in the 2017 GLJ Reserve Report.

Of the 28 gross wells we drilled in 2018, 20 had been booked in the 2017 GLJ Reserve Report. Year-end 2018 2P reserves for these 20 wells amounted to 12.6 mmboe which modestly exceeded the forecast in the 2017 GLJ Reserve Report of 12.4 mmboe. Average 2P F&D costs for these 20 wells was $5.95 per boe, which was modestly higher than forecast resulting from minor operational challenges encountered with drilling and completing two wells in Strachan.

The quality and low risk nature of our future undeveloped reserves is evident with 64% of our booked undeveloped locations being categorized as proved undeveloped reserves, having a 90% or greater probability of achieving the estimated reserves by definition. Over 90% of our future proved plus probable locations exist in close proximity to our owned and operated infrastructure creating an efficient and effective solution to create value in the future.

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

Reserve Performance Ratios

The following tables highlight our gross reserves, finding and development costs ("F&D costs"), finding, development and acquisition costs ("FD&A costs") and the associated recycle ratios for the trailing three years.

For the years ended December 31	**2018**	2017	2016
Reserves (Mboe):			
Proved producing	**148,613**	154,819	155,907
Total proved	**294,177**	275,008	273,183
Proved plus probable	**458,881**	437,743	414,205
Capital Expenditures ($ millions):			
Exploration and development	**164.5**	289.0	153.9
Acquisitions, net of dispositions[4]	**6.0**	(7.8)	(167.9)
Operating Netback ($/boe)[1]:			
Current year	**12.64**	13.85	13.44
Three-year weighted average	**13.32**	14.55	17.54

FINDING AND DEVELOPMENT COSTS

For the years ended December 31	**2018**	2017	2016
Proved Developed Producing:			
Change in FDC ($ thousands)	**(1,822)**	(11,818)	(173)
Reserves additions (Mboe)	**16,368**	25,902	15,831
F&D costs ($/boe)[2]	**9.94**	10.70	9.71
F&D recycle ratio[3]	**1.3**	1.3	1.4
F&D three-year weighted costs ($/boe)[2]	**10.22**	10.95	12.04
F&D recycle ratio three-year weighted average[3]	**1.3**	1.3	1.5
Total Proved:			
Change in FDC ($ thousands)	**103,924**	(41,615)	86,377
Reserves additions (Mboe)	**32,521**	28,237	26,972
F&D costs ($/boe)[2]	**8.25**	8.76	8.91
F&D recycle ratio[3]	**1.5**	1.6	1.5
F&D three-year weighted costs ($/boe)[2]	**8.62**	8.11	10.40
F&D recycle ratio three-year weighted average[3]	**1.5**	1.8	1.7
Total Proved plus Probable:			
Change in FDC ($ thousands)	**45,850**	75,423	60,902
Reserves additions (Mboe)	**31,012**	47,923	30,824
F&D costs ($/boe)[2]	**6.78**	7.60	6.97
F&D recycle ratio[3]	**1.9**	1.8	1.9
F&D three-year weighted costs ($/boe)[2]	**7.19**	7.34	9.11
F&D recycle ratio three-year weighted average[3]	**1.9**	2.0	1.9

FINDING, DEVELOPMENT AND ACQUISITION COSTS

For the years ended December 31	2018	2017	2016
Proved Developed Producing:			
Change in FDC ($ thousands)	**(1,822)**	(13,638)	(2,269)
Reserves additions (Mboe)	**18,493**	25,182	18,879
FD&A costs ($/boe)[2]	**9.12**	10.62	(0.86)
FD&A recycle ratio[3]	**1.4**	1.3	(15.6)
FD&A three-year weighted costs ($/boe)[2]	**6.71**	8.22	9.69
FD&A recycle ratio three-year weighted average[3]	**2.0**	1.8	1.8
Total Proved:			
Change in FDC ($ thousands)	**151,132**	(38,762)	111,576
Reserves additions (Mboe)	**44,350**	28,095	36,004
FD&A costs ($/boe)[2]	**7.25**	8.63	2.71
FD&A recycle ratio[3]	**1.7**	1.6	5.0
FD&A three-year weighted costs ($/boe)[2]	**6.10**	5.50	7.81
FD&A recycle ratio three-year weighted average[3]	**2.2**	2.6	2.2
Total Proved plus Probable:			
Change in FDC ($ thousands)	**94,511**	95,119	(3,821)
Reserves additions (Mboe)	**46,320**	49,808	32,756
FD&A costs ($/boe)[2]	**5.72**	7.56	(0.55)
FD&A recycle ratio[3]	**2.2**	1.8	(24.4)
FD&A three-year weighted costs ($/boe)[2]	**4.84**	4.86	6.42
FD&A recycle ratio three-year weighted average[3]	**2.8**	3.0	2.7

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".
(2) Both F&D and FD&A costs take into account reserves revisions during the year on a per boe basis. Reference should be made to the section entitled "Oil and Gas Advisories".
(3) Recycle ratio is defined as operating netback per boe divided by either F&D or FD&A costs per boe. Reference should be made to the section entitled "Oil and Gas Advisories".
(4) Expenditures on property acquisitions, net of property dispositions.

2018 CAPITAL, OPERATIONS AND FINANCIAL UPDATE

Net capital expenditures[1] for 2018 were $171.3 million a 39% decrease from 2017 levels at $281.7 million. We remained committed to disciplined reinvestment levels, preserving cash flow from operating activities to allocate towards the reduction of our net debt[1]. Exploration and development expenditures were $164.5 million with $122.1 million allocated to drilling 24.9 net wells and completing 28.4 net wells. The remaining $42.4 million was spent on support capital, primarily crown land acquisitions and infrastructure enhancements. Our expenditures on acquisition, net of dispositions totaled $6.0 million, of which property acquisition comprised $32.7 million and property dispositions comprised $26.6 million.

Deep Basin Operations

In 2018, 35% of exploration and development expenditures were invested in our Deep Basin core area. Of the $58 million total exploration and development expenditures in this area, $44 million was allocated to value capital and $14 million to support capital. During the year, we drilled 10 gross (7.1 net) wells mainly in the Wilrich, Notikewin, Falher and Bluesky formations.

Average 2018 production in our Deep Basin core area was 27,496 boe per day comprised of 88% natural gas. Although the oil and natural gas liquids production was only 12% of total Deep Basin production, it is predominately (approximately 70%) oil and condensate production.

In 2018, we completed the initial phase of our farm-in at Edson and tied in the majority of the production into our Ansell facility. The Edson area, northwest of Ansell, is an attractive multi-zone area with three prospective zones (Notikewin, Falher and Bluesky) successfully tested to-date. The Notikewin formation has been the most prolific with the first well having a peak monthly raw gas rate of 9.0 mmcf per day and averaging 6.5 mmcf per day over the first ten months of production. Our second Notikewin well was brought on in late December and is performing in a similar fashion in the first few weeks of production. At a well cost of $3.2 million to drill, complete, equip and tie-in, this play has an outstanding production efficiency of approximately $3,500 per boe per day.

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

The three well Bluesky program at Edson has averaged 3.3 mmcf per day per well over six months with a modest decline rate of only 11%. The value of these reliable Bluesky production profiles are enhanced with 18 barrels per mmcf of NGLs, 60% of which is condensate.

In the current low natural gas price environment, our 2018 Ansell Wilrich development was curtailed to the drilling of only three wells. The final two wells have just recently been brought on production.

West Central Operations

In 2018, 61% of exploration and development expenditures were invested in our West Central core area. Of the $100 million total exploration and development expenditures in this area, $79 million was allocated to value capital and $21 million to support capital. During the year, we drilled, completed and placed on production 18 gross wells (17.8 net wells) comprised of 11 gross (10.8 net) Glauconite wells, six gross (6.0 net) Falher wells and one gross (1.0 net) Notikewin well. Average 2018 production in our West Central core area was 38,563 boe per day comprised of 41% oil and natural gas liquids.

The focus for development activity in West Central core area shifted to the Strachan area in 2018 where 44% of exploration and development expenditures were allocated. The drilling of six gross (5.8 net) wells resulted in the addition of 4,290 boe per day cumulatively, in the final month of 2018 which equates to a cost to add production of $7,640 per boe per day. This is a significant improvement over our 2017 program given that our cost per meter of lateral drilled has decreased by 24% from 2017 to 2018. Furthermore, targeting liquids rich areas of the reservoir resulted in our NGL ratio increasing 22% to 55 barrels per mmcf of raw gas, 40% of which is condensate. Lastly, the connection to the Ricinus facility in June has resulted in a reduction of natural gas shrinkage from 15% to 9%.

The next most active area in West Central was our Morningside Falher play where we spent 24% of our exploration and development expenditures and drilled six gross (6.0 net) wells. The 2018 wells averaged 4.7 mmcf per day of raw gas per well over the first month of production which was a 31% improvement over our 2017 program. These results were heavily influenced by our drilling activity extending the play north of our historical development. The Morningside Falher play continues to demonstrate excellent metrics as the six well program resulted in cumulative production additions in the last month of 2018 of 3,430 boe per day for a production efficiency of $5,540 per boe per day.

Lastly, in the Hoadley Glauconite play our focus in 2018 was in Willesden Green, an area of the reservoir characterized with greater NGL content. The five gross (5.0 net) wells drilled in 2018 averaged 676 boe per day per well over the first three months of production, a 45% improvement over our 2017 program. The horizontal lateral length for the 2018 program was 17% longer with our well costs only four percent higher. The five well program resulted in production additions of 3,070 boe per day in the final month of 2018 generating a production efficiency of $5,530 per boe per day.

Acquisitions and Divestitures

In 2018, property acquisition expenditures amounted to $32.7 million and proceeds from property dispositions totaled $26.6 million for a net expenditure of $6.0 million. The majority of these expenditures were associated with swap transactions where we conducted five swaps for undeveloped land and two swaps that involved production and cash proceeds. We also closed three property acquisitions where the assets acquired were synergistic with our existing operations. In total, all the acquisition and dispositions activity resulted in a net gain of 402 boe per day of production and significant 2P reserve additions, in the 2018 GLJ Reserve Report, of 15.3 mmboe resulting in attractive reserve additions costs of $3.63 per boe including changes in FDC. These acquired assets included high-quality development opportunities with seven proved locations on these lands included in our 2019 budget.

Corporate Production

We achieved annual average production of 69,154 boe per day in 2018. This annual average production was four percent lower than 2017 resulting from a 39% ($110 million) reduction in net capital expenditures in 2018 relative to 2017 triggered by an uncertain commodity price outlook. This spending strategy allowed us to create incremental financial flexibility with the repayment of $60.0 million of long-term debt. Production volumes throughout the year were also impacted by various third party processing constraints and turnarounds, ethane rejection and production curtailments due to NGTL maintenance and inadequate pipeline egress out of the WCSB. These events resulted in a total curtailment of approximately 2,100 boe per day for 2018.

Production Revenues, Marketing and Risk Management

Production revenues for the year totaled $531.0 million inclusive of $16.1 million of realized gains on financial instrument commodity contracts, a decrease of approximately eight percent over the prior year of $578.6 million. A majority of the $47.5 million decrease can be attributed to the four percent decrease in production volumes from the prior year. Production revenues, inclusive of realized gains on financial instrument commodity contracts, on a per boe basis decreased four percent to $21.04 from the prior year of $21.97, the decrease was primarily the result of the decline in natural gas pricing year-over-year due to the volatility of AECO natural gas pricing caused by maintenance on the NGTL system in Alberta. Notwithstanding these pressures, our realized natural gas price, inclusive of realized gains on financial instrument commodity contracts, for 2018 was $2.78 per mcf, an 87% premium to the average AECO daily spot price of $1.49 per mcf. Hedging activities throughout the year led to a $0.60 per mcf premium in our realized natural gas price, a $6.64 per boe discount to our realized NGL price and a $9.61 per boe discount to our realized oil price.

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

Operating and Transportation Expenses

Aggregate operating expenses of $143.9 million declined two percent from $147.2 million in 2017, largely due to lower production volumes. This was offset by per unit operating costs modestly increasing by 11 cents on the year from $5.59 per boe to $5.70 per boe. The majority of the per unit cost increase was due to the temporary shut-in of wells in response to low natural gas prices, third-party turnarounds activities and ethane rejection, partially offset by our development focus on our core assets with low cost structures.

Transportation expenses for the year were $33.7 million as compared to $24.9 million in 2017 with natural gas transportation making up approximately 90% of the 2018 total. The full impact of the firm service pipeline transportation tolls for transporting natural gas to Dawn placed into service in November of 2017 contributed to our 2018 transportation expenses by $12.2 million as compared to a $2.0 million impact in 2017.

General, Administrative and Interest Expenses

General and administrative expenses for 2018 were $24.3 million compared to $24.7 million in 2017. Gross general and administrative costs were eight percent lower in the year resulting from reduced staffing levels and our continued commitment of reducing costs. The cost savings garnered in 2018, however, were offset by reduced capital overhead recoveries due to our reduced exploration and development spending in the year. Capital overhead recoveries were $2.9 million as compared to $4.8 million in 2017, this reduction in overhead recoveries offset the positive impact achieved from reducing our overall general and administrative expenditures associated with running our business.

Interest expenses for 2018 decreased $3.0 million to $35.1 million in 2018 as compared to $38.1 million in 2017 due to lower average debt levels year-over-year.

Cash Flow from Operating Activities and Adjusted Funds Flow

Cash flow from operating activities for the year ended 2018 was $291.2 million a decrease of 11% from the year ended 2017 of $325.6 million. The decrease in cash flow from operating activities was largely due to the 4% decline in production volumes, in addition to realized revenue declining to $21.04 per boe from $21.97 per boe, inclusive of gains on financial commodity instrument contracts.

For the year ended December 31, 2018, adjusted funds flow[(1)] decreased 14% to $259.6 million ($1.00 per share, basic) from $302.0 million ($1.18 per share, basic) for the same period of 2017. The decrease in adjusted funds flow was primarily due to lower natural gas and natural gas liquids production volumes and lower natural gas prices, partially offset by an increase in natural gas liquids prices.

Long-Term Debt

Long-term debt of $801.6 million increased by $1.1 million from year-end 2017 of $800.5 million. Long-term debt consists of $13.0 million CAD drawn on our $500.0 million CAD dollar bank credit facility and $789.7 million CAD in senior unsecured notes ($565 million US and $20.0 million CAD) with a current average remaining life of 3.5 years. Despite allocating $60.0 million from cash flow from operating activities to reduce long-term debt in 2018, our stated long-term debt levels were virtually unchanged as a result of changes to the CDN$/US$ exchange rate and the corresponding impact on the revaluation of our US denominated senior unsecured notes.

Foreign exchange forward contracts of $400 million US have been entered into in order to protect the balance sheet from the impact of a fluctuating CDN$/US$ currency, these contracts at the end of 2018 had an asset value of $17.2 million.

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

2019 OUTLOOK AND CAPITAL PLANS

The western Canadian natural gas sector has experienced numerous distressed pricing events throughout 2018:

- For 2018, Canadian AECO natural gas prices averaged C$1.44 per GJ, a 22-year low at the AECO hub;
- In the fourth quarter, Canadian natural gas prices averaged US$1.43 per mmbtu a 61% discount to the average natural gas price in the US of US$3.64 per mmbtu for the same period; and
- In December, western Canadian AECO prices averaged C$1.67 per mcf while prices immediately south and east of our western Canadian borders were C$4.80 per mcf and C$4.93 per mcf, respectively.

The quality of our abundant natural gas resources in western Canada are competitive with most natural gas plays in North America. The challenge we face in Canada is the lack of pipeline and export egress for the product we produce. Our competitive supply is being constrained by exhaustive regulation creating a lack of export infrastructure to our borders. This, in turn is causing severe discounts in Canadian pricing and providing a competitive advantage to our most fierce competitor, the Unites States of America ("US"). This disadvantage has become clear with 50% growth in US natural gas production from 2007 to 2015 while western Canadian production has shrunk during the same time period.

Major transformations are underway for the global energy sector, from growing electrification to the globalization of natural gas markets. Growth in global gas trade is accelerating given the accessibility of natural gas with the increasing investment in liquefied natural gas ("LNG") and policy efforts to combat air pollution, both key drivers of natural gas demand. As developing economies replace coal-fired generation with modern and efficient gas-fired generation, emissions can be reduced.

Natural gas is clearly becoming the fossil fuel of choice around the globe. Annual volumes of LNG exported around the world has grown significantly from approximately 14 bcf per day in 2001 to approximately 46 bcf per day in 2018. Current forecasts are that by 2035, world LNG production will reach approximately 100 bcf per day. With up to 1,800 tcf of marketable resources in place in Canada, clearly, we as Canadians have an opportunity like no other to supply the rest of the world with clean, environmentally and socially responsible energy.

While natural gas use in advanced economies is expected to grow over the next 20 years, Asia is expected to remain the primary driver of demand growth. With world demand for natural gas currently on the rise, China is expected to outpace Japan as the world's largest gas-importing country this year with imports continuing to grow and expected to catch the level of the EU by 2040. There should be no other country that can compete like Canada to provide LNG to China, a developing country looking for a reliable, responsible source of clean energy.

The US is also responding much quicker to the growth in world demand for LNG. While both Canada and the US began in a similar position in 2010, the US will be exporting in excess of nine bcf per day by year-end. Unfortunately, here in Canada we cannot share the same success story.

Fortunately, the door has recently been opened with a positive final investment decision in late 2018 for the initial phase of LNG Canada on the west coast of our country. The first phase of this project, calling for up to two bcf per day of demand has initial exports scheduled for 2024. This announcement has provided an increased level of confidence in export markets for Canadian natural gas. We expect to see updates in 2019 on other LNG export project proposals, which if met with cooperation from our policy makers and the citizens of Canada, could add up to four bcf per day of incremental natural gas exports in due course.

In 2018, we proudly celebrated our 21st year of efficient operations in western Canada creating value for our shareholders through financial stewardship, sustainable development and cost-effective production of high quality Canadian natural resources. Canadian energy production standards are global benchmarks for sustainable development and environmental protection. Canadian natural gas is the one of the most responsible and environmentally friendly hydrocarbons in the world. It is a reliable, efficient and affordable source of energy developed under leading regulatory and labour standards. Substitution of higher carbon fuels with greater use of Canadian natural gas by international consumers is a net global environmental benefit.

Our business philosophy in 2019 will be similar to our approach in 2018. In the current subdued commodity price environment, we see little economic incentive to grow our business. Hence, we intend to allocate capital to our highest quality development opportunities whereby we maintain production from January to December. We will focus on maximizing cash flow from operating activities with a goal to generate adjusted funds flow(1) in excess of what is required to maintain our forecasted production. We plan to allocate these funds to reduce our net debt(1) to strengthen our balance sheet and enhance our future financial flexibility. In addition, we intend to continue investing in land and infrastructure in the current environment to prepare our asset portfolio for maximum value creation in the future.

Our 2019 capital program is forecasted to range between $130 and $170 million, of which approximately $110 to $130 million will be allocated to our value capital program. Approximately, three quarters of our development capital is set to be spent in our West Central area with the remainder being allocated to the Deep Basin core area. With minimal commitments across our portfolio, we intend to remain flexible with capital allocation and responsive to changing commodity prices. The remaining $20 to $40 million will be allocated to support capital intended to strengthen our asset portfolio for the future.

Our predictable asset base and reliable capital program allows us to maintain our exit production year-over-year between 67,000 and 69,000 boe per day. Continued ethane rejection forecasted in 2019 and a significant third party turnaround season negatively impacts our forecasted annual production. In June, we are forecasting a production curtailment of approximately 10,000 boe per day due to turnaround activity alone. Hence, we expect annual production to be between 65,000 and 69,000 boe per day.

Currently, we have approximately 60% of our forecasted 2019 production hedged with hedges in place for all products that we produce. Specifically, our natural gas marketing strategy has minimized our exposure to the daily AECO hub with less than 17% of our forecasted natural gas production throughout the summer of 2019 being exposed to AECO volatility. Lastly, we have approximately 70 mmcf per day of our natural gas diversified to sales points beyond AECO.

The 2019 plan(2) is designed to generate approximately $170 to $200 million of adjusted funds flow(1) at current strip prices and is expected to lead to the reduction of net debt(1) reduction for the fourth consecutive year.

We thank our employees for their commitment and dedication, our Board of Directors for their guidance and our shareholders for their long-term support.

Notes:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

(2) Reference should be made to section titled "2019 Guidance" in Management's Discussion and Analysis ("MD&A") for the three months and year ended December 31, 2018.

BONAVISTA ENERGY CORPORATION
Supplemental Financial Information
Consolidated Statements of Financial Position

As at December 31	2018	2017
($ thousands)(unaudited)		
Assets		
Current assets		
Accounts receivable	**54,711**	73,451
Prepaid expenses and other assets	**13,993**	14,680
Financial instrument commodity contracts	**57,192**	64,496
Financial instrument contracts	**1,200**	—
	127,096	152,627
Financial instrument commodity contracts	**19,898**	10,260
Financial instrument contracts	**17,204**	—
Property, plant and equipment	**2,633,494**	2,658,352
Exploration and evaluation assets	**126,017**	138,231
Total assets	**2,923,709**	2,959,470
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**101,629**	125,242
Current portion of decommissioning liabilities	**11,704**	16,146
Dividends payable	**2,555**	2,518
Financial instrument commodity contracts	**2,663**	38,146
	118,551	182,052
Financial instrument commodity contracts	**5,226**	10,423
Financial instrument contracts	**—**	19,295
Long-term debt	**801,625**	800,544
Other long-term liabilities	**4,070**	6,603
Decommissioning liabilities	**419,042**	393,180
Deferred income taxes	**23,011**	7,912
Total liabilities	**1,371,525**	1,420,009
Shareholders' equity		
Shareholders' capital	**2,870,931**	2,852,643
Exchangeable shares	**89,417**	93,266
Contributed surplus	**53,168**	56,531
Deficit	**(1,461,332)**	(1,462,979)
Total shareholders' equity	**1,552,184**	1,539,461
Total liabilities and shareholders' equity	**2,923,709**	2,959,470

BONAVISTA ENERGY CORPORATION
Supplemental Financial Information
Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
($ thousands, except per share amounts)(unaudited)				
Revenues				
Production	**124,302**	147,188	**514,967**	553,002
Royalties	**(5,544)**	(8,066)	**(34,360)**	(41,677)
Production revenues, net of royalties	**118,758**	139,122	**480,607**	511,325
Financial instrument commodity contracts				
Realized gains on financial instrument commodity contracts	**268**	8,685	**16,083**	25,566
Unrealized gains (losses) on financial instrument commodity contracts	**139,841**	(9,187)	**43,014**	107,614
Production revenues, net of royalties and financial instrument commodity contracts	**258,867**	138,620	**539,704**	644,505
Expenses				
Operating	**35,383**	38,343	**143,935**	147,165
Transportation	**8,602**	7,584	**33,728**	24,871
General and administrative	**5,413**	6,819	**24,291**	24,749
Share-based compensation	**1,732**	2,614	**10,381**	15,702
Loss (gain) on disposition of property, plant and equipment	**12,057**	(135)	**6,725**	(13,589)
Loss (gain) on disposition of exploration and evaluation assets	**9**	963	**(167)**	(976)
Depletion, depreciation, amortization and impairment	**56,177**	280,514	**227,447**	469,555
Net finance costs	**22,958**	16,727	**66,450**	21,209
Total expenses	**142,331**	353,429	**512,790**	688,686
Income (loss) before taxes	**116,536**	(214,809)	**26,914**	(44,181)
Deferred income tax expense (recovery)	**35,309**	(55,660)	**15,099**	(16,251)
Net income (loss) and comprehensive income (loss)	**81,227**	(159,149)	**11,815**	(27,930)
Net income (loss) per share				
Basic	**0.31**	(0.62)	**0.05**	(0.11)
Diluted	**0.30**	(0.62)	**0.04**	(0.11)

BONAVISTA ENERGY CORPORATION
Supplemental Financial Information
Consolidated Statements of Changes in Equity

($ thousands)(unaudited)	Shareholders' Capital	Exchangeable Shares	Contributed Surplus	Deficit	Total Shareholders' Equity
Balance as at December 31, 2016	2,837,945	93,859	53,449	(1,425,009)	1,560,244
Net loss	—	—	—	(27,930)	(27,930)
Conversion of restricted incentive and performance incentive awards	13,994	—	(13,994)	—	—
Tax effect on conversion of restricted incentive and performance incentive awards	111	—	—	—	111
Share-based compensation expense	—	—	15,702	—	15,702
Share-based compensation capitalized	—	—	1,374	—	1,374
Exchangeable shares exchanged for common shares	593	(593)	—	—	—
Dividends declared	—	—	—	(10,040)	(10,040)
Balance as at December 31, 2017	2,852,643	93,266	56,531	(1,462,979)	1,539,461
Net income	**—**	**—**	**—**	**11,815**	**11,815**
Conversion of restricted incentive and performance incentive awards	**14,439**	**—**	**(14,439)**	**—**	**—**
Share-based compensation expense	**—**	**—**	**10,381**	**—**	**10,381**
Share-based compensation capitalized	**—**	**—**	**695**	**—**	**695**
Exchangeable shares exchanged for common shares	**3,849**	**(3,849)**	**—**	**—**	**—**
Dividends declared	**—**	**—**	**—**	**(10,168)**	**(10,168)**
Balance as at December 31, 2018	**2,870,931**	**89,417**	**53,168**	**(1,461,332)**	**1,552,184**

BONAVISTA ENERGY CORPORATION
Supplemental Financial Information
Consolidated Statements of Cash Flows

	Three months ended December 31,		Year ended December 31,	
	2018	2017	**2018**	2017
($ thousands)(unaudited)				
Cash provided by (used in):				
Operating Activities				
Net income (loss)	**81,227**	(159,149)	**11,815**	(27,930)
Adjustments for:				
Depletion, depreciation, amortization and impairment	**56,177**	280,514	**227,447**	469,555
Share-based compensation	**1,732**	2,614	**10,381**	15,702
Unrealized losses (gains) on financial instrument commodity contracts	**(139,841)**	9,187	**(43,014)**	(107,614)
Loss (gain) on disposition of property, plant and equipment	**12,057**	(135)	**6,725**	(13,589)
Loss (gain) on disposition of exploration and evaluation assets	**9**	963	**(167)**	(976)
Net finance costs	**22,958**	16,727	**66,450**	21,209
Deferred income tax expense (recovery)	**35,309**	(55,660)	**15,099**	(16,251)
Decommissioning expenditures	**(2,198)**	(5,746)	**(12,318)**	(17,318)
Changes in non-cash working capital items	**10,151**	5,200	**8,773**	2,831
Cash flow from operating activities	**77,581**	94,515	**291,191**	325,619
Financing Activities				
Dividends paid	**(2,554)**	(2,517)	**(10,131)**	(10,015)
Interest paid	**(14,159)**	(18,048)	**(32,951)**	(39,344)
Net repayment of long-term debt	**(896)**	(45,227)	**(60,015)**	(79,464)
Cash flow used in financing activities	**(17,609)**	(65,792)	**(103,097)**	(128,823)
Investing Activities				
Exploration and development	**(45,172)**	(59,722)	**(164,492)**	(289,029)
Property acquisitions	**(29,211)**	(2,961)	**(32,654)**	(13,736)
Property dispositions	**18,174**	5,035	**26,616**	21,577
Office equipment	**(221)**	(9)	**(760)**	(557)
Changes in non-cash working capital items	**(3,542)**	(10,617)	**(16,804)**	(1,028)
Cash flow used in investing activities	**(59,972)**	(68,274)	**(188,094)**	(282,773)
Change in cash	**—**	(39,551)	**—**	(85,977)
Cash, beginning of period	**—**	39,551	**—**	85,977
Cash, end of period	**—**	—	**—**	—

NON-GAAP MEASURES

Throughout this document we have made reference to 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 including interest expense. Where working capital is equal to current assets less current liabilities.

  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. For the three months ended December 31, 2018 the non-discretionary component of Bonavista's decommissioning expenditures was $0.6 million (December 31, 2017 - $1.3 million). Similarly, for the year ended December 31, 2018 the non-discretionary component of Bonavista's decommissioning expenditures was $3.6 million (December 31, 2017 - $3.1 million).

  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, fund its dividend program and meet its financial obligations. Bonavista considers its capital structure to include working capital (excluding associated assets and liabilities from financial instrument commodity contracts and decommissioning liabilities), bank credit facility, senior unsecured notes and shareholders' equity. Bonavista monitors capital based on the ratio of net debt to adjusted funds flow (annualized current quarter).

- "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 volumes sold in the period.

  Bonavista's management believes that operating netback is a key industry benchmark and a measure of operating performance that assists management and investors in assessing Bonavista's profitability. Operating netback on a per boe basis assists Bonavista's management and investors in evaluating operating performance on a comparable basis.

- "Cash costs" are 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 sold in the period.

  Bonavista's management uses cash costs in assessing the Corporation's operating efficiency and controllable cost structure. Bonavista’s management believes that cash costs is a useful measure used by investors when evaluating Bonavista’s operating performance. Cash costs on a per boe basis also assists Bonavista’s management and investors in evaluating Bonavista's cash costs on a comparable basis with prior periods.

- "Net debt" is equal to Bonavista's 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. Bonavista has calculated net debt based on the bank credit facility and senior unsecured notes, net of working capital. Working capital has been adjusted to exclude the current portion of financial instrument commodity contracts and the current portion of decommissioning liabilities. Management has excluded the current portion of financial instrument commodity contracts as they are subject to a high degree of volatility prior to ultimate settlement. Similarly, management has excluded the current portion of the decommissioning liability as this is an estimate based on management's assumptions and subject to volatility based on changes in cost and timing estimates, the risk-free discount rate and inflation rate.

- "Net capital expenditures" is equal to cash flow used in investing activities, excluding changes in non-cash working capital.

  Bonavista considers net capital expenditures to be a useful measure of cash flow used for capital reinvestment.

Reference should be made to our 2018 Annual Report for additional disclosure on these non-GAAP measures, including reconciliations to the most comparable GAAP measure. In addition, with respect to adjusted funds flow and net debt, readers should also refer to note 8, "Capital Management" of the financial statements.

OIL AND GAS ADVISORIES

The evaluation of Bonavista's reserves was done in accordance with the definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional reserves information as required under NI 51-101 will be included in our Annual Information Form which will be filed on SEDAR on or before March 31, 2019.

The reserve estimates contained in the document represent our gross reserves, unless otherwise specified, at December 31, 2018 and are defined under NI 51-101, as our interest before deduction of royalties without including any of our royalty interests. All future net revenues are estimated using forecast prices, arising from the anticipated development and production of our reserves, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs and are stated prior to provision for interest and general and administrative expenses. Future net revenues have been presented on a before tax basis.

It should not be assumed that the present worth of estimated future net revenues presented in this document represents the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserves estimates of our crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Reference has been made to the following oil and gas terms "finding and development costs" ("F&D costs") and "finding, development and acquisition costs" ("FD&A costs"), "F&D recycle ratio", "FD&A recycle ratio" and "reserve life index" ("RLI") which have been prepared by management and do not have standardized meanings or standard calculations and therefore such measures may not be comparable to similar measures used by other entities. These terms are used by Bonavista's management to measure the success of replacing reserves and to compare operating performance to previous periods on a comparable basis. For additional information on these measures reference should be made to Bonavista's Annual Information Form which is available through SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

- Finding and development costs ("F&D costs") are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.
- Finding, development and acquisition costs ("FD&A costs") are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category. Both finding and development costs and finding, development and acquisition costs take into account reserve revisions during the year on a per boe basis.
- The F&D recycle ratio is calculated by dividing the operating netback(1) per boe for the period by the F&D costs per boe for the particular reserve category.
- The FD&A recycle ratio is calculated by dividing the operating netback(1) per boe for the period by the FD&A costs per boe for the particular reserve category.
- The reserve life index is calculated based on the amount for the relevant reserve category divided by the production forecast as prepared by Bonavista's reserve engineers GLJ.

Note:

(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Reference should be made to the section entitled "Non-GAAP Measures".

Cost to add production is determined by dividing the yearly capital exploration and development expenditures by the year-end production adds. The year-end production adds are determined by subtracting the current year exit production from the prior year exit production, adjusted for any acquisition or disposition volumes, added to the base yearly decline volumes.

The estimated net asset value is based on the estimated net present value of all future net revenue from Bonavista's proved plus probable reserves, discounted at 10%, before tax, as estimated by GLJ, at year-end, with and without the estimated value of Bonavista's undeveloped acreage and net debt. Common share values in Bonavista's net asset value per share metric are calculated by including outstanding common shares and exchangeable shares which are converted into common shares on certain terms and conditions.

Any reference to value capital, support capital and production efficiency have been prepared by management and are used to measure performance. These terms do not have standardized meanings or standard calculations and are not comparable to similar measures used by other entities.

- Value capital includes expenditures on drilling, completion, equipping and tie-in projects and recompletions. Value capital has been used to define capital expenditures, included in exploration and development expenditures, that are directly associated with generating incremental reserves and cash flow from operating activities.
- Support capital includes expenditures on land, facilities and infrastructure and workovers and facilities. Support capital has been used to define capital expenditures, included in exploration and development expenditures, that are associated with maintenance existing operations and to support future development.

- Production efficiency which is defined as a type of capital efficiency that measures the cost to add an incremental barrel of flowing production. Specifically, for the average production efficiencies of our plays, Bonavista uses the total actual/projected drill, complete and tie-in capital divided by the total of the wells' initial production rate.

Any reference 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 caution not to place reliance on such rates in calculating the aggregate production for Bonavista.

Certain information in this document may constitute "analogous information" as defined in NI 51-101 with respect to offset well production and drilling results from other producers with operations that are in geographical proximity to or believed to be on-trend with Bonavista's assets. Management of Bonavista believes the information may be relevant to help determine the expected results that Bonavista may achieve within Bonavista's lands and such information has been presented to help demonstrate the basis for Bonavista's business plans and strategies. There is no certainty that the results of the analogous information or inferred thereby will be achieved by Bonavista and such information should not be construed as an estimate of future production levels, reserves or the actual characteristics and quality of Bonavista's assets.

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.

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

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

FORWARD-LOOKING INFORMATION

This document should be read in conjunction with the Management's Discussion and Analysis ("MD&A") and the consolidated financial statements (the "financial statements") for the three months and year ended December 31, 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, 2018, are available through SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

This document 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" or "future orientated financial information" in the document as defined by applicable securities laws, has been approved by our management. Such financial outlook or future orientated financial information is provided for the purpose of providing information about our 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 and statements pertaining to the following:

- our focus and plans to create maximum shareholder value;
- expectations regarding our financial flexibility in the future;
- expectations regarding the quality, predictability, resilience and sustainability of our asset base;
- the performance characteristics of our oil and natural gas properties;
- our exploration and development plans and the results therefrom;
- expectations regarding industry conditions, future commodity prices and demand for natural gas;
- our 2019 capital expenditure budget;
- our ability to be agile in responding to changes to commodity prices;
- expectations for 2019 for production volumes, adjusted funds flow, net debt and payout ratio;
- expectations of future production rates, volumes and production mixes;
- expectations regarding reserves volumes, reserve values, reserve life index, future development costs and decline rates;

- our acquisition and infrastructure plans;
- expectations regarding the number and quality of our undeveloped locations; and
- our focus on creating incremental financial flexibility.

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

By their nature, forward-looking statements are subject to numerous risks and uncertainties; some of which are beyond our 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, access to market, production curtailment and ethane rejection, 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. Our 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 we 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.

This document contains information from publicly available third party sources as well as industry data prepared by management on the basis of its knowledge of the industry in which Bonavista operates (including management's estimates and assumptions relating to the industry based on that knowledge). Management's knowledge of the oil and natural gas industry has been developed through its experience and participation in the industry. Management believes that its industry data is accurate and that its estimates and assumptions are reasonable, but Bonavista has not independently verified the accuracy or completeness of this data. Third-party sources generally state that the information contained therein has been obtained from sources believed to be reliable, but Bonavista has not independently verified the accuracy or completeness of included information. Although management believes it to be reliable, Bonavista has not independently verified any of the data from third-party sources referred to in this document or analyzed or verified the underlying studies or surveys relied upon or referred to by such sources, or ascertained the underlying economic assumptions relied upon or referred to by such sources.

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

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

FOR FURTHER INFORMATION CONTACT:

Jason E. Skehar	or	Dean M. Kobelka
President & CEO		Vice President, Finance & CFO

Bonavista Energy Corporation
1500, 525 - 8th Avenue SW
Calgary, AB T2P 1G1
Phone: (403) 213-4300
Website: www.bonavistaenergy.com