Bonavista Announces 2019 Fourth Quarter and Year End Results and 2020 Capital Plan

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Calgary, February 13, 2020 - Bonavista Energy Corp. (TSX: BNP) ("Bonavista") is pleased to report to shareholders its financial and operating results for the three months and year ended December 31, 2019. 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

2019 underscores another year committed to enhancing corporate sustainability through the consolidation and optimization of assets within our core area operations. Prudent and practical capital allocation, establishing a position in the Duvernay shale resource play and environmental stewardship were all highlights throughout the year.

There is no better example than the acquisition completed on December 4, 2019 of 48.4 mmboe total proved and probable reserves ("2P") and 8,340 boe per day of liquids rich natural gas and oil production. Located in the heart of our operations in our West Central core area, this acquisition is valued at $316 million, the future net revenue attributable to our gross proved plus probable reserves discounted at a rate of 10%, before deducting future income tax expenses ("BTNPV10") inclusive of both active and inactive liability and based upon GLJ's January 1, 2020 price forecast effective as at December 31, 2019. The addition of this low decline, predictable production base complemented our existing operations while enhancing the economic quality of our future development plans.

2019 firmly established Bonavista as a Duvernay player in the emerging liquids-rich play with the accumulation of over 211 net sections of prospective Duvernay mineral rights and the drilling of our first horizontal well in this resource play. Industry has been successfully delineating and developing this vast condensate-rich reservoir over the past few years and we look forward to learning from these efforts and prudently allocating capital accordingly over the coming five years.

We replaced 138% of 2019 total production volumes through the addition of 31.9 mmboe of proved developed producing ("PDP") reserves, inclusive of 12.2 mmbbls of PDP NGL reserves equal to 195% of 2019 natural gas liquids ("NGL") production with net capital expenditures amounting to 97% of adjusted funds flow. Prudent capital allocation resulted in a 41% improvement in PDP finding, development and acquisition ("FD&A") costs to $5.42 per boe and a 21% improvement in our production efficiency to $10,290 per boe per day, notwithstanding allocating 29% of our capital program to land, seismic and facilities expenditures.

For 22-years, Bonavista has taken great pride in our environmental and social responsibilities as we protect and restore the environment we operate in. Over the past decade, we have spent $198.3 million, equal to six percent of our exploration and development ("E&D") expenditures over this period, to reclaim and retire our inactive liabilities. In 2019, alone we spent $9.7 million managing our liabilities largely allocated to the abandonment and reclamation of 81 and 25 wells respectively. The estimated net present value of our total decommissioning liability has been reduced over the course of 2019 by 14% to $370.6 million at December 31, 2019. On a final environmental note, in 2019 we invested $2.8 million on environmental risk mitigation of which $1.6 million was allocated to various emission reduction technologies eliminating nearly 65 mtonnes of CO_2e emissions from our operations.

Notwithstanding volatile and unpredictable commodity prices experienced throughout 2019, we successfully hedged and diversified the sales points of our natural gas portfolio allowing us to achieve a realized natural gas price premium of 37% as compared to the average benchmark AECO natural gas price.

Our operating, financial, reserve and environmental stewardship highlights in 2019 once again prove the quality, resilience and sustainability of our asset base. The integrity and philosophy of our capital allocation over the course of the past few tumultuous years in the Canadian energy sector will undoubtedly enhance our ability to create shareholder value in the future.

2019 FOURTH QUARTER FINANCIAL AND OPERATING HIGHLIGHTS

- Strategically enhanced our operating presence in our West Central core area with a significant property acquisition which closed on December 4, 2019. This acquisition added 8,340 boe per day, 23.8 mmboe of PDP reserves and $177 million of PDP BTNPV10 value, inclusive of active and inactive liability, based upon GLJ's January 1, 2020 price forecast.
- Modestly improved daily production over the prior quarter to 62,923 boe per day despite the absence of any operated drilling activity throughout the quarter;
- Enhanced oil and natural gas liquids weighting of our production to 33% in December from 31% a year ago.
- Adjusted funds flow per boe increased 37% over the third quarter.

	Three Months Ended			Year ended	
	September 30, 2019	December 31, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Financial ($ thousands, except per share)					
Production revenues	69,542	100,742	124,302	372,405	514,967
Net income (loss)	(307,489)	(44,201)	81,227	(389,997)	11,815
Per share(1)	(1.16)	(0.17)	0.31	(1.48)	0.05
Cash flow from operating activities	37,113	47,952	77,581	195,736	291,191
Per share(1)	0.14	0.18	0.30	0.74	1.13
Adjusted funds flow(2)	34,565	47,702	61,075	180,972	259,595
Per share(1)	0.13	0.18	0.23	0.69	1.00
Dividends declared	-	-	2,555	2,558	10,168
Per share	-	-	0.01	0.01	0.04
Total assets	2,547,412	2,495,297	2,923,709	2,495,297	2,923,709
Shareholders' equity	1,212,177	1,169,757	1,552,184	1,169,757	1,552,184
Long-term debt(4)	766,569	805,767	801,625	805,767	801,625
Net debt(2)	801,921	808,588	835,905	808,588	835,905
Net capital expenditures(2)	27,332	67,983	56,430	174,628	171,290
Exploration and development	43,284	11,966	45,172	139,550	164,492
Acquisitions, net of dispositions(3)	(16,299)	55,637	11,037	33,923	6,038
Corporate	347	380	221	1,155	760
Weighted average outstanding equivalent shares: (thousands)(1)					
Basic	264,991	265,195	260,047	263,147	258,781
Diluted	275,435	275,492	267,135	272,619	265,671

NOTES:

(1) Basic per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.

(2) 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".

(3) Property acquisitions, net of proceeds on property dispositions.

(4) Long-term debt includes $207.7 million of the current portion of long-term debt for the three months and

year ended December 31, 2019. There was no long-term debt classified as current in the comparative 2018 period or in the three months ended September 30, 2019.

Share Trading Statistics	Three months ended			
	December 31, 2019	September 30, 2019	June 30, 2019	March 31, 2019
($ per share, except volume)				
High	0.63	0.86	1.20	1.39
Low	0.45	0.41	0.46	1.06
Close	0.61	0.61	0.49	1.11
Average Daily Volume - Shares	261,785	462,855	589,117	531,298

	Three Months Ended			Year ended	
	September 30, 2019	December 31, 2019	December 31, 2018	December 31, 2019	December 31, 2018
Operating (boe conversion - 6:1 basis)					
Production:					
Natural gas (mmcf/day)	260	260	281	266	297
Natural gas liquids (bbls/day)	17,310	18,003	19,131	17,162	17,366
Oil (bbls/day)(1)	1,813	1,587	2,108	1,804	2,221
Total oil equivalent (boe/day)	62,437	62,923	68,011	63,357	69,154
Product prices:(2)					
Natural gas ($/mcf)	2.02	2.39	2.91	2.32	2.78
Natural gas liquids ($/bbl)	19.98	27.34	24.99	24.97	29.30
Oil ($/bbl)(1)	63.24	60.51	28.47	61.47	53.07
Total oil equivalent ($/boe)	15.78	19.23	19.91	18.26	21.04
Operating expenses ($/boe)	5.59	5.76	5.66	5.76	5.70
Transportation expenses ($/boe)	1.38	1.37	1.37	1.40	1.34
General and administrative expenses ($/boe)	0.90	0.86	0.87	0.89	0.96
Cash costs ($/boe)(3)	9.42	9.55	9.27	9.56	9.39
Operating netback ($/boe)(3)	8.49	11.04	11.99	10.35	12.64

NOTES:

(1) Oil includes light, medium and immaterial amounts of heavy oil.

(2) Product prices include realized gains and losses on financial instrument commodity contracts.

(3) 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".

Q4 2019 Capital Program

Net capital expenditures increased to $68.0 million in the quarter from $27.3 million in the third quarter of 2019. In the fourth quarter we spent $12.0 million on exploration and development activities, down from $43.3 million spent in the prior quarter to allow for the investment in the synergistic property acquisition that closed in the latter part of the quarter. We drilled 0.2 net wells in the quarter as compared to 5.5 net wells in the third quarter of 2019. Remaining exploration and development expenditures were primarily focused on completion projects with two (1.5 net) wells completed in the fourth quarter in addition to ongoing infrastructure projects.

Q4 2019 Production

Production volumes for the quarter averaged 62,923 boe per day consisting of 260 mmcf per day of natural gas, 18,003 boe per day of natural gas liquids and 1,587 bbl per day of oil. Our 2019 fourth quarter production volumes were similar to that of the prior quarter at 62,437 boe per day despite the impact of disposition and acquisition activity. Non-core assets at Kaybob were disposed of in mid-September, which impacted fourth quarter average production by approximately 1,400 boe per day. The decrease was offset by incremental production volumes from the synergistic property acquisition that closed on December 4, 2019, which positively impacted fourth quarter average production volumes by approximately 2,500 boe per day.

Q4 2019 Production Revenue, Marketing and Risk Management

Production revenues for the fourth quarter, including $10.6 million of realized gains on financial instrument commodity contracts, were $111.3 million, or $19.23 per boe, representing a 22% increase on a per boe basis from prior quarter. Realized pricing on natural gas volumes in the quarter was $2.39 per mcf, an 18% increase from the previous quarter and representing a three percent premium over the average AECO monthly index. Financial hedging accounted for a pricing premium of $0.03 per mcf and $6.07 per bbl for natural gas and natural gas liquids, respectively. Production revenues, excluding realized gains on financial instrument commodity contracts, were $100.7 million or $17.40 per boe

Q4 2019 Operating and Transportation Expenses

Operating expenses for the fourth quarter, displayed a modest three percent increased to $5.76 per boe from $5.59 per boe in the third quarter. The slight increase in costs can largely be attributed to the acquisition of assets occurring late in the fourth quarter that currently have a higher operating cost structure per boe than our corporate average.

Transportation expenses were relatively unchanged between the fourth and third quarter of 2019 at $1.37 per boe and $1.38 per boe, respectively. Similarly, absolute transportation costs of $7.9 million in the fourth quarter compared to $7.9 million in the third quarter.

Q4 2019 General, Administrative and Interest Expenses

General and administrative expenses decreased four percent in the current quarter to $5.0 million as compared to $5.2 million in the third quarter, due to lower salaries and benefits recorded in the quarter.

Interest expenses of $9.0 million recorded in the fourth quarter of 2019 were comparable to the $8.9 million recorded in the third quarter of 2019.

Q4 2019 Net Loss and Comprehensive Loss

For the fourth quarter, we reported a net loss and comprehensive loss of $44.2 million ($0.17 per share, basic) compared to a net loss and comprehensive loss of $307.5 million ($1.16 per share, basic) reported in the prior quarter. The magnitude of the net loss in the prior quarter, was largely due to a $278.0 million impairment charge recognized due to the sustained decline in the forward commodity benchmark prices for natural gas, natural gas liquids and oil. In the fourth quarter an additional impairment charge of $14.3 million was recognized.

Q4 2019 Cash Flow from Operating Activities and Adjusted Funds Flow

Cash flow from operating activities in the fourth quarter of 2019 was $48.0 million, a 29% increase from the third quarter of 2019 of $37.1 million, due to a 23% increase in production revenues, inclusive of gains on financial instrument commodity contracts and on a per boe basis increased to $19.23 per boe from $15.78 per boe in the prior quarter. Adjusted funds flow for the quarter was $47.7 million as compared to $34.6 million in the previous quarter for similar reasons as discussed above.

2019 YEAR IN REVIEW

The quality and predictability of our asset portfolio, combined with the discipline and determination of our technical teams to innovate, enhance development practices and execute on synergistic acquisition opportunities has resulted in a seven percent increase in 2P reserves with reserve additions of 54.1 mmboe replacing 234% of 2019 production while spending 97% of adjusted funds flow. With continued emphasis on light oil and liquids rich natural gas development, we increased oil and NGL PDP reserves by 12% and replaced 183% of 2019 oil and NGL production with PDP reserves.

2019 RESERVE HIGHLIGHTS

- Replaced 234% of 2019 production volumes with the addition of 54.1 mmboe of 2P reserve additions;
- Proved plus probable reserves growth of seven percent to 489.9 mmboe;
- Increased the composition of oil and NGL reserves to 159.2 mmboe or 32% of 2P reserves;
- Invested $55.4 million for the acquisition of synergistic assets in our West Central core area adding 48.4 mmboe of 2P reserves;
- Proved producing FD&A costs improved 41% to $5.42 per boe including changes in future development capital ("FDC") resulting in a proved producing FD&A recycle ratio of 1.9:1;
- Replaced 406% of 2019 NGL production with the addition of 25.4 mmboe of 2P NGL reserve additions. Our corporate 2P NGL ratio increased 12% or eight barrels per mmcf of sales gas resulting in 15% growth in 2P NGL reserves;
- Notwithstanding continued price erosion in GLJ's price forecasts from year-end 2018 to 2019 and a constrained 2019 development program, our 2P BTNPV10 reserves were valued by GLJ at $2,648 million, virtually unchanged from year-end 2018. When adjusted for net debt undeveloped land value and corporate decommissioning liabilities (inflated at 2% and discounted at 10%), our net asset value is approximately $1,921 million, which is equal to $7.24 per share.

2019 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, 2019 as contained in the reserve report of GLJ dated February 3, 2020 (the "2019 GLJ Reserve Report"). The 2019 GLJ Reserve Report used GLJ's forecast price and cost assumptions. The effective date of the forecast prices used in the 2019 GLJ Reserve Report was January 1, 2020.

The reserves data set forth below also contains information regarding our 2018 reserve estimates which were 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.

Reserves Summary

The following table summarizes the estimates of our gross reserves at December 31, 2019 and December 31, 2018, using the forecast price and cost assumptions in effect at the applicable reserve evaluation date:

Reserve Category[(1)]	December 31, 2019	December 31, 2018	% Change
(Mboe)			
Proved:			

Developed Producing	157,390	148,613	6 %
Developed Non-Producing	4,516	9,057	(50) %
Undeveloped	147,104	136,506	8 %
Total Proved	309,010	294,177	5 %
Probable	180,843	164,704	10 %
Total Proved Plus Probable	489,853	458,881	7 %

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, 2019, 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, 2019 before Income Taxes				
(%/year)	0%	5%	10%	15%	20%
	($000s)	($000s)	($000s)	($000s)	($000s)
Proved:					
Developed Producing	1,863,914	1,447,945	1,175,254	989,883	857,84
Developed Non-Producing	38,994	29,909	23,060	18,073	14,403
Undeveloped	1,491,008	878,687	543,357	345,539	220,94
Total Proved	3,393,916	2,356,541	1,741,671	1,353,495	1,093,1
Probable	2,861,179	1,497,349	906,019	606,536	435,11
Total Proved Plus Probable	6,255,095	3,853,890	2,647,690	1,960,031	1,528,3

Notes:

(1) Amounts may not add due to rounding.

(2) Unit values are based on net reserves.

GLJ commodity price forecasts have continued to erode for most products relative to a year ago. The GLJ pricing forecast for 2020 has experienced a nine percent erosion in AECO pricing and a five percent decrease in Edmonton light oil prices. Ethane, propane and pentane pricing has also decreased by 11%, 12%, and two percent respectively while butane price has increased 30%. Despite the continued challenges in both near-term and long-term price forecasts in addition to a restricted capital development program, Bonavista's net present value of future net revenue attributable to Bonavista's 2P BTNPV10 of $2,647.7 million was relatively unchanged when compared to the prior year at $2,635.1 million with a reserve life index of 18.8 years.

The 2019 GLJ Reserve Report includes the abandonment and reclamation liability associated with producing wells and future development locations but does not include inactive wells, facilities, pipelines and gathering systems. Based on Bonavista's decommissioning estimates the liability of these items amount to $42.2 million inflated at 2% and discounted at 10%. This would modestly reduce 2P BTNPV10 value at December 31, 2019 by 1.6% to $2,605.5 million.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of our gross reserves between December 31, 2019 and December 31, 2018 and using the forecast price and cost assumptions in effect at the applicable reserve evaluation date in the 2019 GLJ Reserve Report and 2018 GLJ Reserve Report:

	RECONCILIATION OF GROSS RESERVES BY PRINCIPAL PRODUCT TYPE COSTS(1)			
	Light and Medium Crude Oil(3) (Mbbls)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)	
GROSS TOTAL PROVED				
December 31, 2018	4,749	1,221,589	85,829	
Extensions and Improved Recovery(2)	(6)	56,245	3,682	
Technical Revisions	(151)	7,959	1,242	
Discoveries	-	-	-	
Acquisitions	1,219	118,157	15,606	
Dispositions	(968)	(40,187)	(1,322	
Economic Factors	(19)	(25,326)	(820	
Production	(657)	(97,148)	(6,256	
December 31, 2019	4,168	1,241,288	97,961	
GROSS TOTAL PROBABLE				
December 31, 2018	2,216	717,873	42,842	164,704
Extensions and Improved Recovery(2)	5,150	33,490	3,860	14,592
Technical Revisions	(280)	(19,683)	(898)	(4,458)
Discoveries	-	-	-	-
Acquisitions	601	37,159	5,126	11,921
Dispositions	(512)	(16,289)	(586)	(3,812)
Economic Factors	(20)	(9,629)	(479)	(2,103)
Production	-	-	-	-
December 31, 2019	7,156	742,922	49,866	180,843
GROSS TOTAL PROVED PLUS PROBABLE				
December 31, 2018	6,966	1,939,462	128,671	458,881
Extensions and Improved Recovery(2)	5,144	89,735	7,541	27,641
Technical Revisions	(430)	(11,725)	344	(2,040)
Discoveries	-	-	-	-
Acquisitions	1,821	155,316	20,732	48,438
Dispositions	(1,480)	(56,476)	(1,908)	(12,800)
Economic Factors	(39)	(34,954)	(1,298)	(7,163)
Production	(657)	(97,148)	(6,256)	(23,104)
December 31, 2019	11,324	1,984,210	147,827	489,853

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 immaterial amounts of tight oil and immaterial amounts of heavy oil.

The persistent low-price environment has had a substantial impact on technical revisions due to economic factors. In the 2019 GLJ Reserve Report, economics factors resulted in the reduction of 7.2 mmboe of 2P reserves which is five times greater than the 2018 GLJ Reserve Report. Of these economic factor revisions, 70% were associated with the write down of reserves in two properties in northeast British Columbia which are no longer economic to operate. The deletion of these northeast British Columbia reserves had a negative impact of $3.59 per boe on our corporate 2P F&D. The impact of the 2019 acquisitions and dispositions was the net addition of 35.6 mmboe of 2P reserves at an impressive reserve addition cost of $2.68 per boe and increased to BTNPV10 value of $249 million.

Reserve Performance Ratios

The following tables highlight Bonavista's gross reserves, F&D costs, FD&A costs and the associated recycle ratios for the trailing three years. A decision to curtail 22% of our drilling and completion spending in July in lieu of anticipated M&A activity has resulted in modest erosion of our F&D costs for 2019 given the quantum of this spending level relative to size of our production and reserve base.

Bonavista considers recycle ratio an important measure of long-term profitability. It is measured by dividing the operating netback by the F&D costs per boe or FD&A costs for the year. Bonavista has delivered a three-year weighted average F&D recycle ratio of 1.4:1 and FD&A recycle ratio of 1.8:1 for proved plus probable reserves including revisions and changes in FDC.

For the years ended December 31	2019	2018	2017
Reserves (Mboe):			
Proved producing	157,390	148,613	154,819
Total proved	309,010	294,177	275,008
Proved plus probable	489,853	458,881	437,743
Capital Expenditures ($ millions):			
Exploration and development	139.6	164.5	289.0
Acquisitions, net of dispositions(4)	33.9	6.0	(7.8)
Total capital expenditures	173.5	170.5	281.2
Operating Netback ($/boe)(1):			
Current year	10.35	12.64	13.85
Three-year weighted average	12.36	13.32	14.55

FINDING AND DEVELOPMENT COSTS

For the years ended December 31	2019	2018	2017
Proved Developed Producing:			
Change in FDC ($ thousands)	(1,072)	(1,822)	(11,818)
Reserves additions (Mboe)	11,921	16,368	25,902
F&D costs ($/boe)(2)	11.62	9.94	10.70
F&D recycle ratio(3)			

0.9

1.3

1.3

F&D three-year weighted costs ($/boe)(2)	10.67	10.22	10.95
F&D recycle ratio three-year weighted average(3)	1.2	1.3	1.3
Total Proved:			
Change in FDC ($ thousands)	7,145	103,924	(41,615)
Reserves additions (Mboe)	10,408	32,521	28,237
F&D costs ($/boe)(2)	14.09	8.25	8.76
F&D recycle ratio(3)	0.7	1.5	1.6
F&D three-year weighted costs ($/boe)(2)	9.31	8.62	8.11
F&D recycle ratio three-year weighted average(3)	1.3	1.5	1.8
Total Proved plus Probable:			
Change in FDC ($ thousands)	166,975	45,850	75,423
Reserves additions (Mboe)	18,437	31,012	47,923
F&D costs ($/boe)(2)	16.63	6.78	7.60
F&D recycle ratio(3)	0.6	1.9	1.8
F&D three-year weighted costs ($/boe)(2)	9.05	7.19	7.34
F&D recycle ratio three-year weighted average(3)	1.4	1.9	2.0

FINDING, DEVELOPMENT AND ACQUISITION COSTS

For the years ended December 31	2019	2018	2017
Proved Developed Producing:			
Change in FDC ($ thousands)	(675)	(1,822)	(13,638)
Reserves additions (Mboe)	31,881	18,493	25,182
FD&A costs ($/boe)(2)	5.42	9.12	10.62
FD&A recycle ratio(3)	1.9	1.4	1.3
FD&A three-year weighted costs ($/boe)(2)	8.06	6.71	8.22
FD&A recycle ratio three-year weighted average(3)	1.5	2.0	1.8
Total Proved:			
Change in FDC ($ thousands)	62,285	151,132	(38,762)
Reserves additions (Mboe)	37,938	44,350	28,095
FD&A costs ($/boe)(2)	6.21	7.25	8.63
FD&A recycle ratio(3)	1.7	1.7	1.6
FD&A three-year weighted costs ($/boe)(2)	7.25	6.10	5.50
FD&A recycle ratio three-year weighted average(3)			

1.7

2.2

2.6

Total Proved plus Probable:			
Change in FDC ($ thousands)	288,753	94,511	95,119
Reserves additions (Mboe)	54,076	46,320	49,808
FD&A costs ($/boe)(2)	7.44	5.72	7.56
FD&A recycle ratio(3)	1.4	2.2	1.8
FD&A three-year weighted costs ($/boe)(2)	6.95	4.84	4.86
FD&A recycle ratio three-year weighted average(3)	1.8	2.8	3.0

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.

CORE AREA REVIEW

West Central Operations

In 2019, 79% of our exploration and development ("E&D") expenditures were invested in our West Central core area. Of the $111 million invested in this area, $80 million was allocated to value capital and $31 million was allocated to support capital. During the year we drilled 20 gross wells (18.6 net wells) comprised of 15 gross (13.6 net) Glauconite wells, three gross (3.0 net) Spirit River (Falher) wells, one gross (1.0 net) Cardium well and one gross (1.0 net) Duvernay well. Average 2019 production in the West Central area was 39,269 boe per day comprised of 41% oil and natural gas liquids.

The focus for development expenditures in the West Central core area continued to be in the Strachan area where 49% of the West Central E&D expenditures were allocated. This included drilling seven gross (6.4 net) Glauconite wells and one gross (1.0 net) Cardium well. The last two Glauconite wells in the 2019 program were completed and came on production at the beginning of November and have an average 60-day production rate of 4.4 mmcf per day with wellhead condensate ratios of 12 bbls per mmcf combined with shallow decline rates. The average horizontal lateral length for the 2019 Glauconite wells at Strachan was 19% greater than 2018 and we achieved a 19% reduction in cost per lateral meter drilled. Additional compression was installed in the second half of 2019 which allowed us to achieve peak production at Strachan of 41 mmcf per day in the fourth quarter. This facility addition leaves us with 20 mmcf per day of additional capacity to accommodate the 2020 program which consists of drilling six gross (5.3 net) wells in the Glauconite at Strachan.

The Hoadley Glauconite program accounted for 36% of the West Central E&D expenditures in 2019 with the drilling of seven (7.0 net) wells mainly in the Willesden Green area of the Hoadley Glauconite trend. The average performance of the 2019 wells was characterized with a seven per cent increase in natural gas liquid content when compared to 2018 production performance. The plan for 2020 is to drill six gross (6.0 net) Glauconite wells in the Willesden Green area where four of the extended reach horizontal wells incorporate lands acquired in our property acquisition that occurred in the fourth quarter of 2019.

Three gross (3.0 net) wells were drilled in the Morningside Falher play in 2019 that amounted to eight percent of the West Central E&D program. Well performance continued to improve as the average cost to add production over the first year was $4,500 per boe per day which was an 18% improvement over 2018. While we continue to consolidate land in this area to accommodate extended reach horizontal wells, the 2020 plan will be limited to two gross (2.0 net) wells.

In the fourth quarter, we participated in our first non-operated well in the oil/condensate rich Garrington Glauconite play, a play we acquired in the fourth quarter of 2019. This well was recently completed with rates expected to be 350 bbls per day of light oil and 1.8 mmcf per day of liquids rich natural gas, similar to the offset well. A second well (0.2 net) is planned for the first quarter of 2020.

Deep Basin Operations

In 2019, $24 million or 18% of our E&D expenditures were invested in our Deep Basin core area with $15 million allocated to drilling and completions and $9 million allocated to support capital. With an unsustainable low natural gas price environment this past summer, we only drilled three gross wells (2.6 net wells) comprised of two gross (2.0 net) Wilrich wells and one gross (0.6 net) Cardium well. Average 2019 production in the Deep Basin area was 21,926 boe per day comprised of 88% natural gas.

In late 2018, we brought on our second Notikewin horizontal well at Edson that has produced at an average raw gas rate of 5.5 mmcf per day over the first year of production. At a well cost of $3.4 million to drill, complete, equip and tie-in, this well has outstanding production efficiency of approximately $3,800 per boe per day over the first year of production and a payout of 1.2 years based on 2019 commodity pricing. With limited excess facility capacity in 2019, follow-up development was delayed until 2020 where we will drill two (2.0 net) additional Notikewin wells, including one extended reach horizontal well.

In 2019, we drilled two (2.0 net) and completed three (3.0 net) Ansell Wilrich wells that did not meet expectations resulting from unexpected parent-child inter-well communication. Average production for the three wells is 2.5 mmcf per day over the first 11 months of production. For 2020, we plan to drill three (3.0 net) Wilrich wells northeast of Ansell where there is less prior development and a reservoir that is richer in natural gas liquids.

Duvernay

Meaningful progress was made to enhance our position and delineate the Duvernay play in 2019. During the year, we acquired 30,400 acres of Duvernay rights through crown land sales. This brings our total Duvernay land acreage to 135,000 acres with the majority located within the oil/condensate window of the reservoir. Our first Duvernay well was drilled over 22 days in the third quarter of 2019 which included a pilot vertical well (to capture technical reservoir information) and achieved a lateral length of 3,260 meters. The lateral length for this well was 50% longer than the offsetting Duvernay horizontal wells that had an average initial one-month production rate of 564 bbls per day of light oil and 1.6 mmcf per day of natural gas. We will analyze the technical information retrieved from the vertical pilot and evaluate offsetting well performance before determining our completion strategy in 2020.

Acquisitions and Divestitures

In 2019, property acquisitions amounted to $55.4 million and proceeds from property dispositions totaled $21.5 million for a net expenditure of $33.9 million. The most significant transaction was the fourth quarter acquisition in our West Central area that added approximately 8,340 boe per day of production, 48.4 mmboe of 2P reserves, and $316 million BTNPV10 inclusive of both active and inactive liability and based upon GLJ's January 1, 2020 price forecast effective as at December 31, 2019. This acquisition adds 62.4 net locations to our inventory mainly in the Willesden Green Glauconite play and the Garrington oil/condensate Glauconite play. Since the transaction closed in early December we have made meaningful progress toward our projected 30% reduction in operating costs given the synergy to our West Central core area operations. Current production of the acquired assets is 8,300 boe per day (45% oil and NGL) and we are forecasting production to exit the year in excess of 10,000 boe per day with 23% of 2020 drilling locations planned in our West Central core area on the acquisition lands.

To balance this significant acquisition, we closed two dispositions in 2019 that resulted in disposing of 1,880 boe per day of non-core production for proceeds of $21.5 million. The net effect of the 2019 acquisitions and dispositions was the addition of net 6,460 boe per day of synergistic, low decline production rich in oil and natural gas liquids for $33.9 million.

Corporate Production

We achieved annual average production of 63,357 boe per day in 2019. This annual average production was eight percent lower than 2018 due to a 15% ($24.9 million) reduction in exploration and development expenditures and natural production declines in excess of new well production growth. As a result of an uncertain commodity price outlook in both years, natural declines in well performance have outpaced new well production growth as we have looked to create incremental financial flexibility by allocating funds towards our net debt repayment. Further in both 2019 and 2018, production volumes were impacted by production curtailments in response to uneconomic natural gas prices, the impact of significant scheduled and unscheduled third party turnaround activity, egress constraints and non-core property dispositions. Positively impacting 2019 production was the synergistic property acquisition in our West Central core area that closed on December 4, 2019.

Production, Revenues, Marketing and Risk Management

Production revenues for the year totaled $422.3 million inclusive of $49.9 million of realized gains on financial instrument commodity contracts, a decrease of 20% over the prior year of $531.1 million. The $108.7 million decrease can be attributed to an eight percent decrease in production volumes from the prior year with the remainder due to a substantial decrease in both natural gas liquids and natural gas pricing the result of continued headwinds the industry is facing with egress constraints and supply/demand imbalances. Notwithstanding these pressures, our realized natural gas price, inclusive of realized gains on financial instrument commodity contracts, for 2019 was $2.32 per mcf, a 37% premium to the average benchmark AECO price. Hedging activities throughout the year led to a $0.36 per mcf premium in our realized natural gas price, a $2.56 per bbl premium to our realized NGL price and a $2.07 per bbl discount to our realized oil price.

Operating and Transportation Expenses

Aggregate operating expenses of $133.3 million declined seven percent in 2019 from $143.9 million in 2018, largely due to lower production volumes offset by the seasonality impact of prolonged winter conditions and significant third-party turnaround activity experienced in the first half of 2019. This overall decrease was offset by per unit operating costs modestly increasing by six cents in 2019 from $5.70 per boe to $5.76 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 the fourth quarter acquisition which currently has a higher operating cost structure than our corporate average.

Transportation expenses for the year were $32.5 million as compared to $33.7 million in 2018 with natural gas transportation expenses making up the majority of the total transportation expenses at approximately 90% in both years. On a per unit basis transportation costs increased six cents from $1.34 per boe to $1.40 per boe. The per boe increase was primarily impacted by firm service obligations where transportation restrictions occurred on the NGTL system which reduced utilization but increased firm transportation charges on a per boe basis.

General, Administrative and Interest Expenses

General and administrative expenses for 2019 were $20.6 million compared to $24.3 million in 2018. The 15% reduction in general and administrative costs was largely due to the adoption of IFRS 16, Leases, which changed the accounting treatment of our head office lease, in addition to reduced staffing, compensation levels and our continued commitment of reducing costs.

Interest expenses were relatively unchanged at $34.9 million in 2019 compared to $35.1 million in 2018. The modest decrease in 2019 was primarily due to lower average borrowings on our bank credit facility for the first nine months of the year.

Net Income (Loss) and Comprehensive Income (Loss)

For the year ended 2019, we reported a net loss and comprehensive loss of $390.0 million ($1.48 per share, basic) compared to net income and comprehensive income of $11.8 million ($0.05 per share, basic) in the prior year. The change from a net income position to a net loss position can be attributed to a 20% decrease in production revenues, including realized gains on financial instrument commodity contracts in addition to a $292.3 million impairment charge recognized as a result of a sustained decline in the forward commodity benchmark prices for natural gas, natural gas liquids and oil. The benchmark prices referenced in our impairment test were based on the average price forecasts as prepared by four independent reserve evaluators effective on October 1, 2019 and January 1, 2020.

Cash Flow from Operating Activities and Adjusted Funds Flow

Cash flow from operating activities for the year ended 2019 was $195.7 million a 33% decrease from the year ended 2018 of $291.2 million. The decrease in cash flow from operating activities was primarily due to a 20% decrease in production revenues, including realized gains on financial instrument contracts in addition to an eight percent decrease in production volumes.

For the year ended December 31, 2019, adjusted funds flow decreased 30% to $181.0 million ($0.69 per share, basic) from $259.6 million ($1.00 per share, basic) for the same period of 2018. The decrease in adjusted funds flow was primarily due to lower realized natural gas and natural gas liquids prices and an eight percent decline in production volumes.

Long-term Debt and Net Debt

For the year ended 2019 long-term debt, including the current portion of long-term debt of $207.7 million, was $805.8 million. This was an increase of $4.1 million from year-end 2018 of $801.6 million. Long-term debt consists of $53.2 million CAD drawn on our bank credit facility and $753.9 million CAD in senior unsecured notes ($565 million US and $20.0 million CAD) with a current average remaining life of 2.5 years. The slight increase in our long-term debt balance was the result of drawings on our bank credit facility in the fourth quarter to close the synergistic property acquisition partially offset by the result of changes to the CDN$/US$ exchange rate and the corresponding impact on the revaluation of our US denominated senior unsecured notes.

Net debt for the year ended 2019 was $808.6 million as compared to $835.9 million for the year ended 2018 with the difference largely due to the revaluation of our US denominated senior unsecured notes (2019 - $1.2990 USD/CAD compared to 2018 - $1.3641 USD/CAD).

2020 OUTLOOK AND CAPITAL PLANS

With the flip of the calendar page, a new year and a new decade begins. And with it, a forecast that the first half of the coming decade will undoubtedly be more constructive than the last half of the previous one for the Canadian energy sector. We closed the books on 2019 and look forward to a year that could bring a change in tone for the energy landscape in North America.

Having endured back to back years of challenging AECO pricing, largely due to a contracting imbalance of supply and demand on the NGTL system, the year ended on a relatively positive note with establishment of the Temporary Service Protocol ("TSP"). With overwhelming support of the majority of stakeholders, including the Government of Alberta, TSP has and will meaningfully improve the supply and demand fundamentals of operation on the NGTL system during times of construction and maintenance this summer, creating a more efficient market in the short term.

As for the long-term, the $10 billion multi-year expansion of the NGTL system through Alberta and northeastern British Columbia is well underway. It is designed to increase transportation capacity and egress for Canadian producers resulting in a total demand increase of 3.5 bcf per day. In addition, the $6.6 billion Coastal GasLink pipeline project to connect to the LNG Canada plant in Kitimat, the first large-scale liquefied natural gas ("LNG") export facility in Canada, has progressed with 32% of the route cleared and construction underway across the 670-kilometer route. Notably, almost $1 billion in contracts have been awarded since the Final Investment Decision ("FID") of LNG Canada in October 2018 leaving no doubt that this project, the largest privately-funded infrastructure project in Canadian history, will fundamentally change the natural gas sector in western Canada for decades to come.

With the extended period of critically low natural gas pricing conditions, particularly through 2019, Canadian natural gas supplies fell for the first time in seven years. The reduced supply following 24-months of limited drilling activity and strengthened market access certainly sets a constructive foundation for Canadian natural gas as we move into the coming decade. The supply story south of the border has followed a remarkably different path. Production rates for dry gas outpaced consumption growth in the US and in conjunction with mild weather, caused an inventory build through the winter months. NYMEX February natural gas futures fell to three-year lows earlier in the year and have not been able to fully recover in the wake of the coronavirus outbreak. Global prices have plunged on concerns that China's demand for all forms of energy will be severely impacted. These market anomalies, while seemingly quite dire over the short term, have not dampened longer-term sentiment meaningfully, but more so have been viewed as a correction in the supply demand imbalance that currently exists. Correspondingly, natural gas production growth is expected to slow in the US in 2020 to be more aligned with demand growth in the coming three years.

Domestic demand in the US has been driven in recent years by increasing base-load natural gas demand within the power generation sector, now feeding about 40% of the market. Natural gas has been steadily replacing coal as a more cost-effective, cleaner energy source to meet growing electrical demand. This phenomenon is not isolated to the US as Canada also marked a record year for natural gas power generation. In the US, the switch from coal to natural gas fired power generation has been a primary contributor to the US significantly reducing GHG emissions in 2019, speaking volumes to the value of natural gas as a clean, reliable source of energy to power the globe.

Alongside significant domestic demand growth, export demand has sky-rocketed in the US. Recent start-ups of new natural gas pipelines built from the US into Mexico have resulted in new daily highs of nearly six bcf per day late last year doubling the export volumes seen four years ago. LNG expansion has provided for significantly more export capacity having grown in that same four-year period from zero to nearly 10 bcf per day at present. Both LNG and Mexican export capacity is forecasted to continue to grow at unprecedented rates in the coming five years.

Given the global market conditions, we remain confident that there is a place at the table for Canadian energy. Forecasts for energy usage over the next decade show significant growth for all sources of energy, particularly natural gas. We are proud to represent Canada on the world stage to aid in the reduction of GHG emissions as the world transitions to cleaner energy and provides for more access to affordable, reliable and modern energy services. Undoubtedly, energy is an ingredient to each and every goal amongst the 17 sustainable development goals adopted by the General Assembly of the United Nations. Specifically, goal 7 of 17, Affordable and Clean Energy states that "Energy is central to nearly every major challenge and opportunity the world faces today. Be it for jobs, security, climate change, food production or increasing incomes, access to energy for all is essential." Clean Canadian natural gas is clearly available in abundance to serve the world.

In 2019, we remained focused on enhancing sustainability in this continued tumultuous commodity price environment. Working ferociously to strengthen our core operating areas and remain active with acquisitions in a distressed merger and acquisition ("M&A") market has underpinned our success throughout the year. These efforts have created a more predictable and profitable asset portfolio built for reliability in any commodity price environment and destined to generate long-term value for our shareholders.

Our business philosophy over the coming year will remain consistent with that of 2019, with a recurring focus on sustainability and building for the future. Our plan, initially, will be to spend within adjusted funds flow, targeting an E&D program of between $100 and $120 million, the majority allocated to our West Central core area. Spending levels are designed to maintain production levels with those of 2019 and the goal is to generate excess adjusted funds flow for debt repayment. We continue to have on-going negotiations regarding our covenant relief process with both our noteholders and our banking syndicate with the expectation of a successful resolution over the next few months.

Our capital program is designed to be sensitive to market conditions such that we can adapt to preserve adjusted funds flow in any environment. Continued commodity price volatility will keep us agile and flexible with our capital allocation and will undoubtedly lead to conservative organic spend levels as we remain enrolled in the M&A market in our core areas. We fully expect the next 12-months will bring challenges and opportunities, however, we remain confident that we have built a resilient business philosophy to weather the ongoing turbulence as we strengthen our foundation for growth in future years.

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

Bonavista Energy Corp.
Consolidated Statements of Financial Position

As at December 31	2019	2018
($ thousands)(unaudited)		
Assets		
Current assets		
Accounts receivable	59,753	54,711
Prepaid expenses and other assets	14,086	13,993
Financial instrument commodity contracts	39,508	57,192
Financial instrument contracts	-	1,200
	113,347	127,096
Financial instrument commodity contracts	14,789	19,898
Financial instrument contracts	-	17,204
Property, plant and equipment	2,245,876	2,633,494
Exploration and evaluation assets	121,285	126,017
Total assets	2,495,297	2,923,709
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	79,203	101,629
Current portion of long-term debt	207,736	-
Current portion of decommissioning liabilities	8,650	11,704
Dividends payable	-	2,555
Financial instrument commodity contracts	40,568	2,663
Financial instrument contracts	542	-
	336,699	118,551
Financial instrument commodity contracts	26,634	5,226
Financial instrument contracts	138	-

Long-term debt	598,031	801,625
Other long-term liabilities	2,120	4,070
Decommissioning liabilities	361,918	419,042
Deferred income taxes	-	23,011
Total liabilities	1,325,540	1,371,525
Shareholders' equity		
Shareholders' capital	2,881,935	2,870,931
Exchangeable shares	88,963	89,417
Contributed surplus	52,746	53,168
Deficit	(1,853,887)	(1,461,332)
Total shareholders' equity	1,169,757	1,552,184
Total liabilities and shareholders' equity	2,495,297	2,923,709

Bonavista Energy Corp.
Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

	Three months ended December 31,	
	2019	2018
($ thousands, except per share amounts)(unaudited)		
Revenues		
Production	100,742	124,302
Royalties	(6,123)	(5,544)
Production revenues, net of royalties	94,619	118,758
Financial instrument commodity contracts		
Realized gains on financial instrument commodity contracts	10,583	268
Unrealized gains (losses) on financial instrument commodity contracts	(35,293)	139,841
Production revenues, net of royalties and financial instrument commodity contracts	69,909	258,867
Expenses		
Operating	33,333	35,383
Transportation	7,929	8,602
General and administrative	4,961	5,413
Share-based compensation	1,680	1,732
Loss on disposition of property, plant and equipment	222	12,057
Loss (gain) on disposition of exploration and evaluation assets		

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Depletion, depreciation, amortization and impairment	62,374	56,177
Net finance costs	3,611	22,958
Total expenses	114,110	142,331
Income (loss) before taxes	(44,201)	116,536
Deferred income tax expense (recovery)	-	35,309
Net income (loss) and comprehensive income (loss)	(44,201)	81,227
Net income (loss) per share		
Basic	(0.17)	0.31
Diluted	(0.17)	0.30

Bonavista Energy Corp.
Consolidated Statements of Changes in Equity

	Shareholders' Capital	Exchangeable Shares	Contr
($ thousands) (unaudited)			
Balance as at December 31, 2017	2,852,643	93,266	56,53
Net income	-	-	-
Conversion of restricted incentive and performance incentive awards	14,439	-	(14,4
Share-based compensation expense	-	-	10,38
Share-based compensation capitalized	-	-	695
Exchangeable shares exchanged for common shares	3,849	(3,849)	-
Dividends declared	-	-	-
Balance as at December 31, 2018	2,870,931	89,417	53,16
Net loss	-	-	-
Conversion of restricted incentive and performance incentive awards	10,550	-	(10,5
Share-based compensation expense	-	-	9,548
Share-based compensation capitalized	-	-	580
Exchangeable shares exchanged for common shares	454	(454)	-
Dividends declared	-	-	-
Balance as at December 31, 2019	2,881,935	88,963	52,74

Bonavista Energy Corp.
Consolidated Statements of Cash Flows

	Three months ended December 31,				Year ended
	2019		2018		2019
($ thousands)(unaudited)					
Cash provided by (used in):					
Operating Activities					
Net income (loss)	(44,201	)	81,227		(389,997
Adjustments for:					
Depletion, depreciation, amortization and impairment	62,374		56,177		499,290
Share-based compensation	1,680		1,732		9,548
Unrealized losses (gains) on financial instrument commodity contracts	35,293		(139,841	)	82,106
Loss on disposition of property, plant and equipment	222		12,057		15,337
Loss (gain) on disposition of exploration and evaluation assets	-		9		1,772
Net finance costs	1,345		22,958		20,865
Deferred income tax expense (recovery)	-		35,309		(23,011
Decommissioning expenditures	(2,610	)	(2,198	)	(9,743
Changes in non-cash working capital items	(6,151	)	10,151		(10,431
Cash flow from operating activities	47,952		77,581		195,736
Financing Activities					
Dividends paid	-		(2,554	)	(5,113
Interest paid	(16,670	)	(14,159	)	(35,406
Lease payments	(1,286	)	-		(5,178
Monetization of financial instrument contracts	5,857		-		5,857
Net proceeds (repayment) of long-term debt	53,192		(896	)	40,172
Cash flow from (used in) financing activities	41,093		(17,609	)	332
Investing Activities					
Exploration and development	(11,966	)	(45,172	)	(139,550
Property acquisitions	(55,522	)	(29,211	)	(55,395
Property dispositions	(115	)	18,174		21,472
Office equipment	(380	)	(221	)	(1,155
Changes in non-cash working capital items	(21,062	)	(3,542	)	(21,440
Cash flow used in investing activities	(89,045	)	(59,972	)	(196,068
Change in cash					

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Cash, beginning of period	-	-	-
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.

  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. Bonavista considers its capital structure to include working capital (excluding associated assets and liabilities from financial instrument commodity contracts, lease liabilities 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, lease liabilities 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, lease liabilities and 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 2019 Annual Report for additional disclosure on these non-GAAP measures, including reconciliations to the most comparable GAAP measure. In addition, with respect to adjusted fund 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, 2020.

The reserve estimates contained in the document represent our gross reserves, unless otherwise specified, at December 31, 2019 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 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 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.

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, decommissioning liabilities 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 references 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 may not be 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. Support capital has been used to define capital expenditures, included in exploration and development expenditures, that are associated with the maintenance of 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 cautioned 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.

Any references to total oil equivalent are based on Bonavista's production volumes which are comprised of natural gas, natural gas liquids and oil, where oil Includes immaterial amounts of tight oil and immaterial amounts of heavy oil. The total oil equivalent disclosures included in this document are based on the following disaggregation by product:

	West Central		Deep Basin	
	Year ended December 31,		Year ended December 31,	
	2019	2018	2019	2018
Natural gas (mmcf/day)	140	137	115	145
Natural gas liquids (bbls/day)	14,788	14,530	2,260	2,675
Oil (bbls/day)	1,105	1,257	474	650
Total oil equivalent (boe/day)	39,269	38,563	21,926	27,496

	Acquired Properties(1)		Dispositions
	Current	2020 exit	2019 close(1)
Natural gas (mmcf/day)	27	34	7
Natural gas liquids (bbls/day)	3,169	3,650	242
Oil (bbls/day)	686	650	486
Total oil equivalent (boe/day)	8,300	10,000	1,880

NOTES:

(1) Refers to the property acquisition closing on December 4, 2019 in our West Central core area.
(2) Refers to the production divested, based on the closing date of the transaction in 2019.

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
bcf	billion cubic feet
Boe	barrels of oil equivalent
CO2e	carbon dioxide equivalent
Mbbls	thousand barrels
Mboe	thousand barrels of oil equivalent
Mtonne	thousand tonnes
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 condensed consolidated interim financial statements for the three months and year ended December 31, 2019, together with notes related thereto, as well as in conjunction with the audited consolidated financial statements for the year ended December 31, 2018, together with the notes thereto, for a full understanding of the financial position and results of operations of Bonavista Energy Corp. ("Bonavista" or the "Corporation"). Additional information relating to Bonavista, including the audited consolidated financial statements for the year ended December 31, 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 expectations regarding the performance of acquired assets and how they will enhance the economic quality and complement our future development plans in our West Central core area;
- our expectations regarding the Duvernay resource play and our ability to learn from industry and allocate capital in the next five-years;
- our ability to create future shareholder value;
- our future expectations with respect to the energy landscape in North America;
- expectations regarding industry conditions, future commodity prices; demand for energy and natural gas and the impact of LNG on GHG emissions;
- our expectations regarding our ability to be active in merger and acquisition market;
- our expectation that acquisition and divestitures transactions will generate long-term shareholder value;
- our 2020 capital expenditure budget and plans;
- our expectations regarding covenant relief negotiations and there successful outcome;
- 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 reserves volumes, reserve values, reserve life index, future development costs and decline rates;
- 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. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves and future net revenues for all properties, due to the effects of aggregation.

References to future drilling locations do not provide certainty that Bonavista will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves or production. The drilling locations on which Bonavista actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While a certain number of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, some of our other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves or production. Of the 62.2 net horizontal locations relating to the acquired properties, 28.2 are net proved locations, 4.1 are net probable locations and 29.9 are net unbooked locations.

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 relating to the demand for energy 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

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