BONAVISTA

ENERGY CORPORATION

ANNUAL REPORT

- 2019 -

TABLE OF CONTENTS

OVERVIEW

Bonavista Energy Corporation is a Canadian oil and natural gas producer headquartered in Calgary, Alberta.

The year 2020 marks the 23rd year of operations. Over the past two decades, Bonavista has taken pride in being a responsible corporate steward of Canada's natural resources despite commodity price volatility and uncertainty inherent in the energy sector. Bonavista's continued focus has been on creating maximum shareholder value through the efficient development of high-quality natural gas, natural gas liquids and oil assets in the Western Canadian Sedimentary Basin ("WCSB").

Bonavista prides itself on being one of the most responsible and efficient producers in the Canadian energy sector, the result of bringing together excellent people who consistently find better ways of doing things.

References to Bonavista, our, we, and the Corporation used throughout this report refer to Bonavista Energy Corporation. All amounts presented are expressed in Canadian dollars ("CDN") unless otherwise indicated.

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.

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.

On behalf of the Board of Directors,

Jason E. Skehar, President and Chief Executive Officer
February 13, 2020
Calgary, Alberta

FINANCIAL AND OPERATING RESULTS

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 December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
Financial						
($ thousands, except per boe and per share amounts)						
Production revenues	**100,742**	124,302	(19)%	**372,405**	514,967	(28)%
Net income (loss)	**(44,201)**	81,227	(154)%	**(389,997)**	11,815	(3,401)%
Per share[1]	**(0.17)**	0.31	(155)%	**(1.48)**	0.05	(3,060)%
Cash flow from operating activities	**47,952**	77,581	(38)%	**195,736**	291,191	(33)%
Per share[1]	**0.18**	0.30	(40)%	**0.74**	1.13	(35)%
Adjusted funds flow[2]	**47,702**	61,075	(22)%	**180,972**	259,595	(30)%
Per share[1]	**0.18**	0.23	(22)%	**0.69**	1.00	(31)%
Dividends declared	**—**	2,555	(100)%	**2,558**	10,168	(75)%
Per share	**—**	0.01	(100)%	**0.01**	0.04	(75)%
Total assets				**2,495,297**	2,923,709	(15)%
Shareholders' equity				**1,169,757**	1,552,184	(25)%
Long-term debt[4]				**805,767**	801,625	1 %
Net debt[2]				**808,588**	835,905	(3)%
Net capital expenditures[2]	**67,983**	56,430	20 %	**174,628**	171,290	2 %
Exploration and development	**11,966**	45,172	(74)%	**139,550**	164,492	(15)%
Acquisitions, net of dispositions[3]	**55,637**	11,037	404 %	**33,923**	6,038	462 %
Corporate	**380**	221	72 %	**1,155**	760	52 %
Weighted average outstanding equivalent shares: (thousands)[1]						
Basic	**265,195**	260,047	2 %	**263,147**	258,781	2 %
Diluted	**275,492**	267,135	3 %	**272,619**	265,671	3 %

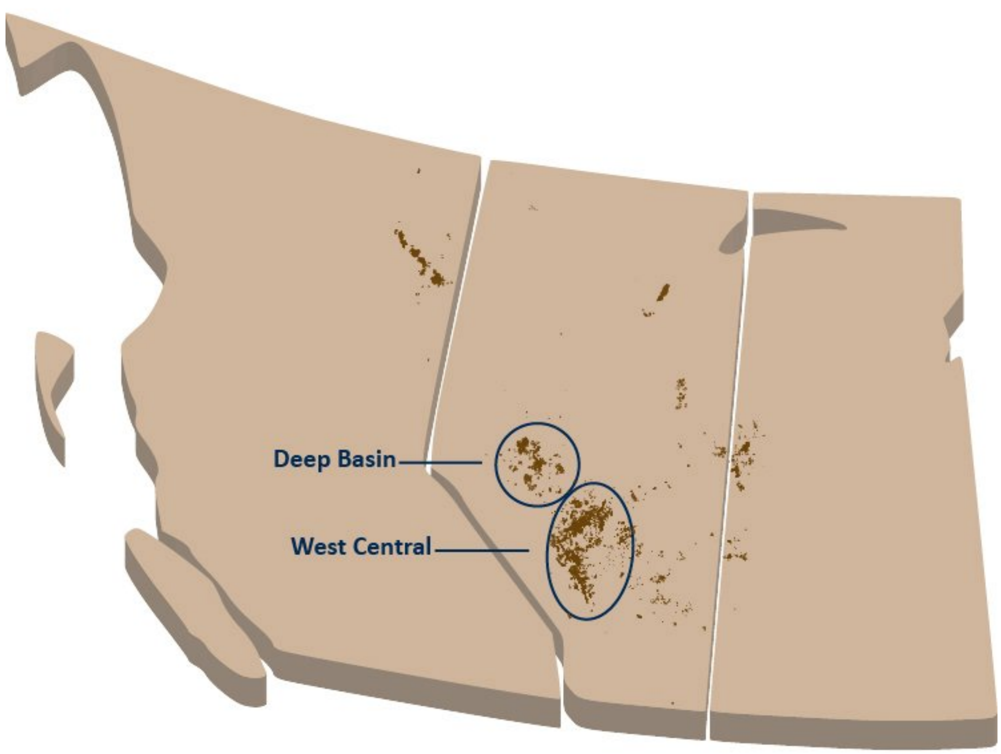
Notes:

(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 includes $207.7 million of the current portion of long-term debt for the year ended December 31, 2019. There was no long-term debt classified as current in the comparative 2018 period.

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
Operating						
(boe conversion – 6:1 basis)						
Production:						
Natural gas (MMcf/day)	**260**	281	(7)%	**266**	297	(10)%
Natural gas liquids (bbls/day)	**18,003**	19,131	(6)%	**17,162**	17,366	(1)%
Oil (bbls/day)(1)	**1,587**	2,108	(25)%	**1,804**	2,221	(19)%
Total oil equivalent (boe/day)	**62,923**	68,011	(7)%	**63,357**	69,154	(8)%
Product prices:(2)						
Natural gas ($/mcf)	**2.39**	2.91	(18)%	**2.32**	2.78	(17)%
Natural gas liquids ($/bbl)	**27.34**	24.99	9 %	**24.97**	29.30	(15)%
Oil ($/bbl)(1)	**60.51**	28.47	113 %	**61.47**	53.07	16 %
Total oil equivalent ($/boe)	**19.23**	19.91	(3)%	**18.26**	21.04	(13)%
Operating expenses ($/boe)	**5.76**	5.66	2 %	**5.76**	5.70	1 %
Transportation expense ($/boe)	**1.37**	1.37	— %	**1.40**	1.34	4 %
General and administrative expenses ($/boe)	**0.86**	0.87	(1)%	**0.89**	0.96	(7)%
Cash costs ($/boe)(3)	**9.55**	9.27	3 %	**9.56**	9.39	2 %
Operating netback ($/boe)(3)	**11.04**	11.99	(8)%	**10.35**	12.64	(18)%

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".

CORE AREA REVIEW

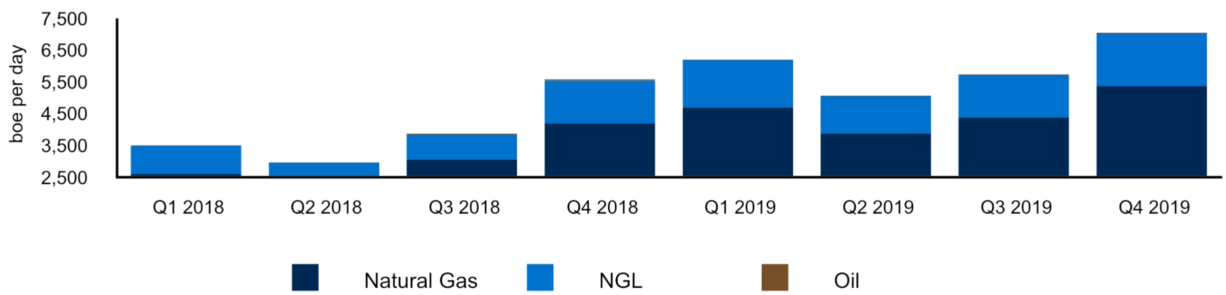


West Central Operations

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.

Production Trend 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.

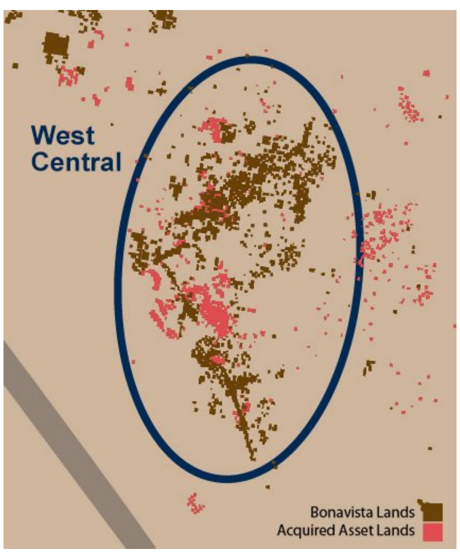
Duvernay

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.



YEAR-END RESERVES

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 Independent Reserves Evaluation

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.

Bonavista retained the independent qualified reserve evaluators, GLJ Petroleum Consultants Ltd. (**"GLJ"**) to evaluate 100% of its 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 Bonavista's 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.

The reserve estimates contained in the following tables represent Bonavista's gross reserves, unless otherwise specified, at December 31, 2019 and are defined under NI 51-101, as the Corporation's interest before deduction of royalties without including any of the Corporation's royalty interests. All future net revenues are estimated using forecast prices, arising from the anticipated development and production of Bonavista's 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 the tables below represents the fair market value of the reserves. There is no assurance that the forecast price and cost assumptions will be attained and variances could be material. The recovery and reserves estimates of Bonavista's 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.

Reference within this section 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. For further information on these terms, refer to the section "Oil and Gas Advisories".

All of Bonavista's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

2019 Reserves 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.

Reserves Summary

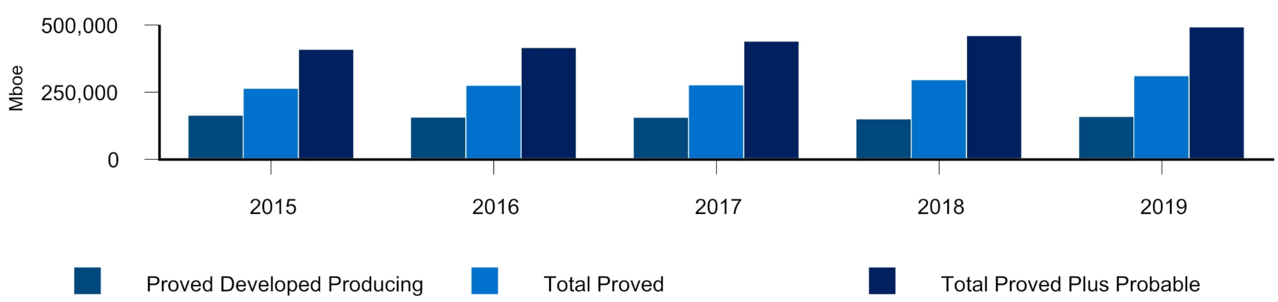
The following table summarizes the estimates of Bonavista's gross reserves at December 31, 2019 and December 31, 2018, using the forecast price and cost assumptions in effect at the applicable reserve evaluation date:

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.

Gross Reserves



Notes:

(1) The reserve report prepared by GLJ dated January 25, 2016 and effective December 31, 2015. The reserve report prepared by GLJ dated February 1, 2017 and effective December 31, 2016. The reserve report prepared by GLJ dated January 31, 2018 and effective December 31, 2017. The reserve report prepared by GLJ dated February 13, 2019 and effective December 31, 2018. The reserve report prepared by GLJ dated February 3, 2020 and effective December 31, 2019.

The following table sets forth Bonavista's crude oil, natural gas liquids and natural gas reserves at December 31, 2019, using GLJ's forecast price and cost assumptions:

Reserve Category(1)	**Crude Oil**(3)(4)		**Natural Gas**(2)(4)		**Natural Gas Liquids**(4)		**Total Reserves**(4)	
	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)	Gross (Mboe)	Net (Mboe)
Proved:								
Developed Producing	3,517	3,193	627,110	570,557	49,355	40,860	157,390	139,145
Developed Non-Producing	313	265	17,041	15,467	1,363	1,098	4,516	3,941
Undeveloped	338	319	597,138	545,774	47,243	41,068	147,104	132,350
Total Proved	4,168	3,777	1,241,289	1,131,797	97,961	83,025	309,010	275,436
Probable	7,156	6,231	742,922	676,365	49,866	41,843	180,843	160,801
Total Proved Plus Probable	11,324	10,008	1,984,210	1,808,163	147,827	124,869	489,853	436,237

Notes:

(1) Amounts may not add due to rounding.
(2) Includes conventional natural gas, shale natural gas and coal bed methane.
(3) Includes light, medium, heavy and tight oil.
(4) "Gross" means Bonavista's working interest (operating or non-operating) share before the deduction of royalties and without including any royalty interests. "Net" means Bonavista's working interest (operating or non-operating) share after the deduction of royalty obligations, plus royalty interests in reserves. Bonavista's gross reserves for 2019 are based on the 2019 GLJ Reserve Report, dated February 3, 2020 effective December 31, 2019. GLJ reserve estimates were based on forecast prices and costs as of January 1, 2020.

Net Present Value of Future Net Revenue

The following table highlights the net present value of future net revenue attributable to Bonavista's 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 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	1,863,914	1,447,945	1,175,254	989,883	857,841	8.45	1.41
Developed Non-Producing	38,994	29,909	23,060	18,073	14,403	5.85	0.98
Undeveloped	1,491,008	878,687	543,357	345,539	220,947	4.11	0.68
Total Proved	3,393,916	2,356,541	1,741,671	1,353,495	1,093,191	6.32	1.05
Probable	2,861,179	1,497,349	906,019	606,536	435,114	5.63	0.94
Total Proved Plus Probable	6,255,095	3,853,890	2,647,690	1,960,031	1,528,305	6.07	1.01

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.

Pricing Assumptions

The forecast price and cost assumptions used in Bonavista's reserves assume primarily an increase in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and foreign exchange rates used in the 2019 GLJ Reserve Report were as follows:

Year	Edmonton Light Crude Oil	WTI Oil	AECO Gas	Foreign Exchange Rate
	(CDN$/bbl)	(US$/bbl)	(CDN$/MMBtu)	(US$/CDN$)
2020	71.71	61.00	2.08	0.7600
2021	74.03	63.00	2.35	0.7700
2022	76.92	66.00	2.55	0.7800
2023	80.13	68.00	2.65	0.7800
2024	82.69	70.00	2.75	0.7800
2025	85.26	72.00	2.85	0.7800
2026	87.82	74.00	2.91	0.7800
2027	90.14	75.81	2.97	0.7800
2028	92.09	77.33	3.03	0.7800
2029	94.08	78.88	3.09	0.7800
Thereafter	2.0%/year	2.0%/year	2.0%/year	0.7800

Note:

(1) GLJ's forecast commodity price report with an effective date January 1, 2020.

Reconciliation of Changes in Reserves

The following table sets forth a reconciliation of Bonavista's 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 FORECAST PRICES AND COSTS[1]				
	Light and Medium Crude Oil[3] (Mbbls)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbls)	Oil Equivalent (Mboe)
GROSS TOTAL PROVED				
December 31, 2018	4,749	1,221,589	85,829	294,177
Extensions and Improved Recovery[2]	(6)	56,245	3,682	13,050
Technical Revisions	(151)	7,959	1,242	2,418
Discoveries	—	—	—	—
Acquisitions	1,219	118,157	15,606	36,517
Dispositions	(968)	(40,187)	(1,322)	(8,987)
Economic Factors	(19)	(25,326)	(820)	(5,060)
Production	(657)	(97,148)	(6,256)	(23,104)
December 31, 2019	**4,168**	**1,241,288**	**97,961**	**309,010**
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.

Future Development Costs ("FDC")

FDC reflects GLJ's best estimate of what it will cost to bring the proved and proved plus probable reserves on production. Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates. The following table sets forth the schedule of FDC required to develop future reserves using the forecast price and cost assumptions in effect at the applicable reserve evaluation date:

Future Development Costs[(1)(2)]	Total Proved	Total Proved plus Probable
	($ thousands)	($ thousands)
2020	138,988	153,158
2021	247,122	315,733
2022	316,083	395,019
2023	251,629	351,126
2024	136,012	275,573
2025	11,403	92,576
2026	576	83,629
2027	2,583	57,130
2028	844	1,237
2029	616	2,151
2030	567	1,489
2031	157	250
Remaining	6,190	9,331
Total (Undiscounted)	1,112,769	1,738,402
Total (Discounted at 10%)	875,313	1,293,552

Notes:

(1) Amounts may not add due to rounding.
(2) Future development costs include both developed and undeveloped reserves.

Total FDC, discounted at 10%, as a ratio of three-year trailing average adjusted funds flow of $247.5 million is 5.2 times demonstrating our practical approach to booking future undeveloped reserves and our ability to sustainably fund the development of those future reserves.

2P FDC increased by 15% compared to 2018, $134.9 million of this increase associated with the addition of 9.6 mmboe of Duvernay reserves and $61.8 million of this increase was the net impact from our acquisition and disposition activity.

Reserve Life Index ("RLI")

Bonavista's business plan is to create premium shareholder value through the efficient development of high-quality natural gas and oil assets. The profitable growth of Bonavista's reserves coupled with the sustainable production of these reserves will generate long-term returns for shareholders. In 2019, Bonavista's proved RLI increased by nine percent to 12.5 years while proved plus probable RLI declined by a modest 13% to 18.8 years demonstrating the long-term sustainable balance that exists between exploration and development expenditures, acquisitions and divestitures, reserves additions and production levels.

The following table sets forth Bonavista's historical RLI:

Reserve Life Index (Years)[(1)]	2015	2016	2017	2018	**2019**
Total Proved	9.7	10.5	10.3	11.5	**12.5**
Total Proved Plus Probable	14.1	14.4	15.2	16.6	**18.8**

Note:

(1) Calculated based on the amount for the relevant reserves category divided by the production forecast for the applicable year prepared by GLJ.

Reserves 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

GENERAL

This Management's discussion and analysis (**"MD&A"**) for Bonavista Energy Corporation (the **"Corporation"** or **"Bonavista"**) is dated February 13, 2020. This MD&A with respect to the three months and year ended December 31, 2019 as compared to the three months and year ended December 31, 2018 has been prepared by management and approved by the Corporation's Audit Committee and Board of Directors. This MD&A should be read in conjunction with the audited consolidated financial statements (the **"financial statements"**) for the year ended December 31, 2019, together with the notes related thereto, for a full understanding of the financial position and results of operations of the Corporation.

The audited consolidated financial statements and comparative information for the year ended December 31, 2019 have been prepared in accordance with International Financial Reporting Standards (**"IFRS"**), as issued by the International Accounting Standard Board ("IASB"). All dollar amounts are presented in Canadian dollars (**"CDN"**), unless otherwise noted.

The MD&A refers to **"adjusted funds flow"**, **"operating netback"**, **"operating margin"**, **"cash costs"**, **"net capital expenditures"**, **"net debt"** and **"payout ratio"**, which do not have standardized meanings as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. For further information, refer to the section "Non-GAAP Measures".

This MD&A contains forward-looking information within the meaning of applicable Canadian securities laws. Such forward-looking information is based upon certain expectations and assumptions and actual results may differ materially from those expressed or implied by such forward-looking information. For further information regarding the forward-looking information contained herein, including the assumptions underlying such forward-looking information, refer to the "Forward-Looking Information" advisories section.

All boe amounts as presented in this MD&A have been calculated using the conversion of six thousand cubic feet of natural gas to one barrel of oil (6 mcf = 1 bbl). For further information refer to the "Oil and Gas" advisories section.

ABOUT BONAVISTA

Bonavista is a Canadian oil and natural gas producer headquartered in Calgary, Alberta. Bonavista's operations are concentrated to its Deep Basin and West Central core areas located in the Western Canadian Sedimentary Basin ("WCSB"). The Deep Basin core area is characterized by stacked, resource-rich reservoirs that are highly prolific and provide solid margin operations when developed and produced through an extensive owned and operated processing infrastructure. The West Central core area draws its strength from an extensive infrastructure and consistent well results often rich in natural gas liquids production. With two core areas Bonavista is structured to respond to changes in its business environment by having flexibility in how capital is allocated to create long-term value for its shareholders. Since inception, it has been Bonavista's priority to bring together the technical, operational and financial talent required to develop its high-quality natural gas and oil assets in the most efficient, responsible and sustainable manner.

Bonavista's common shares are listed for trading on the Toronto Stock Exchange (the "TSX") under the symbol "BNP".

Additional information relating to Bonavista, including the Corporation's Annual Information Form, is available through SEDAR at www.sedar.com or can be obtained from Bonavista's website at www.bonavistaenergy.com.

2020 GUIDANCE

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 exploration and development 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 long-term debt repayment. 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 similar challenges and opportunities as the previous year, 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.

The following table sets forth Bonavista's guidance and commodity price assumptions for 2020, as well as 2019 results for comparative purposes:

	2020 Guidance and Assumptions	2019 YTD Actuals
Production:		
Total oil equivalent (boe/day)	**62,000 - 65,000**	**63,357**
Natural gas (%)	**70%**	**70%**
Natural gas liquids (%)	**27%**	**27%**
Oil (%)	**3%**	**3%**
Expenses ($/boe):		
Royalties	**0.65 - 0.85**	**0.75**
Operating	**6.00 - 7.00**	**5.76**
Transportation	**1.25 - 1.50**	**1.40**
General and administrative	**0.75 - 0.85**	**0.89**
Interest	**1.50 - 1.75**	**1.51**
Net capital expenditures ($ thousands)(1):		
Exploration and development	**100,000 - 120,000**	**139,550**
Acquisitions, net of dispositions, including corporate(2)(3)	**—**	**35,078**
Decommissioning expenditures ($ thousands)	**10,000 - 12,000**	**9,743**
Dividends declared ($ thousands)	**—**	**2,558**
Cash flow from operating activities ($ thousands)	**120,000 - 150,000**	**195,736**
Adjusted funds flow ($ thousands)(1)	**110,000 - 140,000**	**180,972**
Payout ratio (%)(1)	**95% - 100%**	**103%**
Gross Wells (count)	**18 - 22**	**23**
Commodity Prices:		
Average Edmonton light oil price ($/bbl)(4)	**56.00 - 66.00**	**69.21**
Average AECO strip price ($/gj)(4)	**1.50 - 1.90**	**1.67**
Average NYMEX strip price ($/MMbtu)(4)	**1.90 - 2.30**	**2.63**

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) Expenditures on property acquisitions, net of property dispositions.
(3) Corporate capital expenditures refers to expenditures on office equipment.
(4) Commodity price assumptions have been updated to reflect actuals year-to-date.

Notwithstanding natural gas price instability throughout the second half of 2019 as a result of transportation and storage constraints, Bonavista's adjusted funds flow of $181.0 million was three percent above forecast for the year ended December 31, 2019. Production of 63,357 boe per day for the year ended December 31, 2019 was aligned with guidance in-spite of production curtailments in response to unfavourable pricing, unscheduled facility turnarounds and the divestment of non-core properties in the third quarter of 2019. Net capital expenditures of $174.6 million, were higher than initially forecast as a result of the synergistic asset acquisition of approximately 8,340 boe per day closing December 4, 2019. On a per boe basis, transportation, general and administrative and interest expense were aligned with their respective guidance ranges, while royalties were slightly higher than the respective guidance ranges. Royalties were higher than anticipated as a result of a narrowing in the fourth quarter of Bonavista realized commodity prices relative to the respective crown reference pricing on which royalty obligations are calculated.

Future operations

As at December 31, 2019, Bonavista had a working capital deficiency, however, was in compliance with all financial covenants on its bank credit facility and senior unsecured notes. Management's forecasts for 2020 based upon current strip pricing, indicates a potential breach of its total debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment ("EBITDA") and senior debt to EBITDA covenants within the next six months. Management forecasts may change materially based upon actual prices received during the year, changes in future strip pricing and its future business plan. If these financial covenants are not met, the bank credit facility and senior unsecured notes may become due on demand. This material uncertainty may cast significant doubt with respect to the ability of the Corporation to continue as a going concern.

Bonavista is in the process of negotiating covenant relief from its senior noteholders and members of its bank credit facility. No agreements have been reached as of the date of the consolidated financial statements and therefore, there can be no assurance that such agreements will be reached. Bonavista does, however, expect that this negotiation process will be successful and suitable terms for covenant relief reached.

The consolidated financial statements have been prepared on a going concern basis, which presumes that Bonavista will continue its operations for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business. The consolidated financial statements do not reflect adjustments and classifications of assets, liabilities, revenues and expenses which, would be necessary if the Corporation were unable to continue as a going concern.

Dividend update

As a result of the near-term outlook for commodity prices, the Board of Directors suspended Bonavista's quarterly dividend on May 2, 2019. This action reduced Bonavista's annual cash outlays for 2019 by approximately $8 million. The reinstatement of the quarterly dividend program is at the discretion of the Board of Directors.

CASH FLOW FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

The following table sets forth Bonavista's cash flow from operating activities and adjusted funds flow[1] for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands, expert per share amounts)						
Cash flow from operating activities	**47,952**	77,581	(38) %	**195,736**	291,191	(33) %
Per share[2]	**0.18**	0.30	(40) %	**0.74**	1.13	(35) %
Adjusted funds flow[1]	**47,702**	61,075	(22) %	**180,972**	259,595	(30) %
Per share[1][2]	**0.18**	0.23	(22) %	**0.69**	1.00	(31) %

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.

Details of the change in cash flow from operating activities for the three months and year ended December 31, 2019 are provided in the following table:

($ thousands)	Three months ended	Year ended
Cash flow from operating activities - December 31, 2018	77,581	291,191
Volume variance:		
Natural gas	**(4,888)**	**(24,680)**
Natural gas liquids	**(2,996)**	**(2,675)**
Oil	**(1,733)**	**(9,540)**
Price variance:		
Natural gas	**(5,150)**	**(21,431)**
Natural gas liquids	**(12,593)**	**(84,802)**
Oil	**3,800**	**566**
Realized gains on financial instrument commodity contracts	**10,315**	**33,857**
Royalties	**(579)**	**16,983**
Operating expenses	**2,050**	**10,623**
Transportation expenses	**673**	**1,238**
General and administrative expenses	**452**	**3,714**
Financing expenses	**(2,266)**	**(2,266)**
Share-based compensation	**—**	**(413)**
Decommissioning expenditures	**(412)**	**2,575**
Working capital	**(16,302)**	**(19,204)**
Cash flow from operating activities - December 31, 2019	**47,952**	**195,736**

For the three months ended December 31, 2019, cash flow from operating activities decreased 38% to $48.0 million ($0.18 per share, basic) from $77.6 million ($0.30 per share, basic) for the same period of 2018. The decrease in cash flow from operating activities was primarily due to lower average natural gas and natural gas liquids prices, lower production volumes and a reduction in working capital. These decreases were partially offset by an increase in higher average oil prices, an increase in realized gains on financial instrument commodity contracts and lower operating expenses.

For the year ended December 31, 2019, cash flow from operating activities decreased 33% to $195.7 million ($0.74 per share, basic) from $291.2 million ($1.13 per share, basic) for the same period of 2018. The decrease in cash flow from operating activities was primarily due to lower average natural gas and natural gas liquids prices, lower production volumes and a reduction in working capital. The decrease was partially offset by an increase in realized gains on financial instrument commodity contracts, lower royalties, and lower operating and transportation expenses.

For the three months ended December 31, 2019, adjusted funds flow decreased 22% to $47.7 million ($0.18 per share, basic) from $61.1 million ($0.23 per share, basic) for the same period of 2018. The decrease in adjusted funds flow was primarily due to lower natural gas prices, lower natural gas liquids prices and lower production volumes, partially offset by an increase in realized gains on financial instrument commodity contracts coupled with lower operating expenses.

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 the same reasons as noted above.

NET INCOME (LOSS)

The following table sets forth Bonavista's net income (loss) recognized for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands, expert per share amounts)						
Net income (loss)	**(44,201)**	81,227	(154) %	**(389,997)**	11,815	(3,401) %
Per share[1]	**(0.17)**	0.31	(155) %	**(1.48)**	0.05	(3,060) %

Note:

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

Details of the change in net income (loss) for the three months and year ended December 31, 2018 to net income (loss) for the three months and year ended December 31, 2019 are provided in the following table:

($ thousands)	Three months ended	Year ended
Net income - December 31, 2018	81,227	11,815
Change in production revenues	**(23,560)**	**(142,562)**
Change in royalties	**(579)**	**16,983**
Change in realized gains on financial instrument commodity contracts	**10,315**	**33,857**
Change in unrealized gains (losses) on financial instrument commodity contracts	**(175,134)**	**(125,120)**
Change in operating expenses	**2,050**	**10,623**
Change in transportation expenses	**673**	**1,238**
Change in general and administrative expenses	**452**	**3,714**
Change in share-based compensation expenses	**52**	**420**
Change in gains (losses) on dispositions[1]	**11,844**	**(10,551)**
Change in depletion, depreciation, amortization and impairment	**(6,197)**	**(271,843)**
Change in net finance costs	**19,347**	**43,319**
Change in deferred income tax expense (recovery)	**35,309**	**38,110**
Net loss - December 31, 2019	**(44,201)**	**(389,997)**

Note:

(1) Includes the changes in gains and losses on the disposition of property, plant and equipment and exploration and evaluation assets.

Bonavista reported a net loss and comprehensive loss of $44.2 million ($0.17 per share, basic) for the three months ended December 31, 2019, compared to a net income and comprehensive income of $81.2 million ($0.31 per share, basic) reported during the same period of 2018. The change in net loss between the fourth quarter of 2019 and 2018, was primarily due to changes in unrealized gains and losses on financial instrument commodity contracts caused by significant price volatility experienced in commodity markets throughout the fourth quarter of 2018.

Bonavista reported a net loss and comprehensive loss of $390.0 million ($1.48 per share, basic) for the year ended December 31, 2019, compared to a net income and comprehensive income of $11.8 million ($0.05 per share, basic) reported during the same period of 2018. The net loss and comprehensive loss reported in 2019 was largely due to a $292.3 million impairment charge, recorded in the second half of 2019. The impairment charge resulted from a sustained decline in the forward commodity benchmark prices for natural gas, natural gas liquids and oil. In addition, a decline in production revenues and changes in unrealized gains and losses on financial instrument commodity contracts contributed to the net loss position for the year ended December 31, 2019. These decreases were partially offset by higher realized gains on financial instrument commodity contracts, a decrease in net finance costs and a reduction in deferred income tax expense.

DISCUSSION OF OPERATIONS

The following table sets forth Bonavista's drilling activity for the three months and year ended December 31, 2019:

	Three months ended December 31, 2019		Year ended December 31, 2019	
	Gross	Net	Gross	Net
Wells drilled[1]	**1**	**0.2**	**23**	**21.2**
Wells completed[2]	**2**	**1.5**	**22**	**20.9**
Wells brought on production[3]	**5**	**4.2**	**23**	**20.4**

Notes:

(1) Based on rig release date.
(2) Based on frac end date.
(3) Based on first production date tied-in to permanent facilities.

Consistent with Bonavista's asset concentration strategy, exploration and development activities in 2019 were focused on Bonavista's Deep Basin and West Central core areas. These two core areas provide Bonavista with the ability to allocate capital to ensure the most economic plays are pursued in response to changes in commodity prices. This flexibility has been fundamental to Bonavista's capital program in 2019, as the Corporation remains focused on creating incremental financial flexibility by spending within adjusted funds flow.

As a result of the synergistic asset acquisition closing in the fourth quarter of 2019, Bonavista's exploration and development spending was reduced to $12.0 million for the three months ended December 31, 2019. This spending was primarily focused on completion projects with two (1.5 net) wells completed in the fourth quarter along with ongoing support capital projects. In the fourth quarter of 2019 there was one gross (0.2 net) non-operated well drilled in the West Central core area.

For the year ended December 31, 2019, Bonavista invested $139.6 million on exploration and development projects drilling 20 gross (18.6 net) liquids rich natural gas wells in the West Central core area and three gross (2.6 net) natural gas wells in the Deep Basin core area. Most development drilling in the West Central core area was focused on Bonavista's most economic plays in the current price environment with 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. The development in the Deep Basin core area included two gross (2.0 net) Spirit River (Wilrich) wells and one gross non-operated (0.6 net) Cardium well.

Production

The following table sets forth Bonavista's production by product category for the three months and year ended December 31:

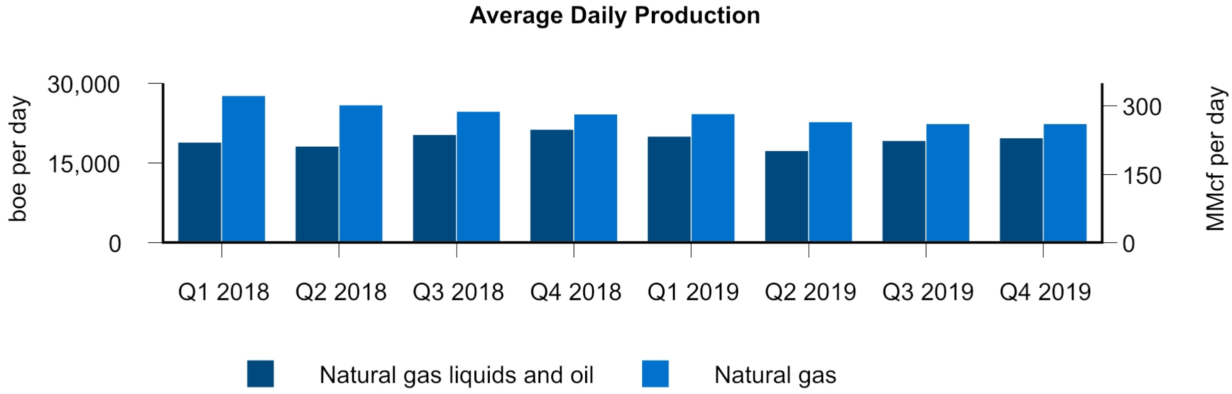
	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
Natural gas (mmcf/day)	**260**	281	(7)%	**266**	297	(10)%
Natural gas liquids (bbls/day)	**18,003**	19,131	(6)%	**17,162**	17,366	(1)%
Oil (bbls/day)	**1,587**	2,108	(25)%	**1,804**	2,221	(19)%
Total oil equivalent (boe/day)	**62,923**	68,011	(7)%	**63,357**	69,154	(8)%
Natural gas liquids by component (bbls/day)						
Ethane (C_2)	**5,846**	7,094	(18)%	**5,600**	5,381	4 %
Propane (C_3)	**5,261**	4,972	6 %	**4,994**	5,048	(1)%
Butane (C_4)	**2,920**	2,840	3 %	**2,765**	2,754	— %
Pentanes plus and condensate (C_{5+})	**3,976**	4,225	(6)%	**3,803**	4,183	(9)%
Natural gas liquids (bbls/day)	**18,003**	19,131	(6)%	**17,162**	17,366	(1)%

Production volumes for the three months ended December 31, 2019 averaged 62,923 boe per day, a seven percent decrease compared to an average of 68,011 boe per day for the same period of 2018. The decrease in average production volumes over the same prior year period resulted from natural production declines in excess of new well production growth. In addition, on September 16, 2019, Bonavista disposed of non-core assets in the Deep Basin area which impacted fourth quarter average production by approximately 1,400 boe per day. These decreases were partially 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.

For the three months ended December 31, 2019, natural gas production averaged 260 mmcf per day, a seven percent decrease compared to an average of 281 mmcf per day for the same period of 2018. Natural gas liquids production was 18,003 bbls per day for the three months ended December 31, 2019, a six percent decrease when compared to 19,131 bbls per day for the same period of 2018. The decrease in natural gas and natural gas liquids production was largely due to a reduction in new well production as a result of a reduced capital development program and the disposition in the third quarter of 2019 of non-core assets in the Deep Basin area. Oil production decreased 25% to 1,587 bbls per day for the three months ended December 31, 2019 compared to 2,108 bbls per day for the same period of 2018, due to natural production declines in mature light oil assets and the disposition of light oil properties in the third quarter of 2019 and the second half of 2018.

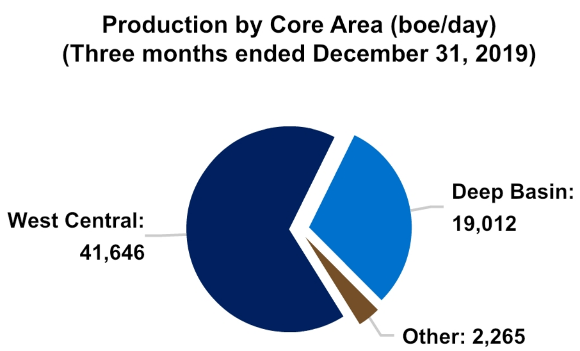
Production volumes for the year ended December 31, 2019 averaged 63,357 boe per day, an eight percent decrease compared to an average of 69,154 boe per day for the same period of 2018. The decrease in average production volumes over the same prior year period was largely due to a reduced exploration and development program, production curtailments in response to uneconomic natural gas prices, the impact of significant scheduled and unscheduled third party turnaround activity in the second quarter of 2019 and ongoing NGTL pipeline maintenance.

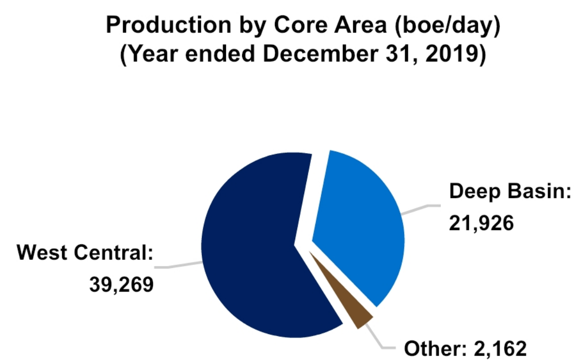
For the year ended December 31, 2019, natural gas production averaged 266 mmcf per day, a ten percent decrease compared to an average of 297 mmcf per day for the same period of 2018. The decrease period over period is due to similar reasons as noted above. Natural gas liquids production was 17,162 bbls per day for the year ended December 31, 2019, a one percent decrease when compared to 17,366 bbls per day for the same period of 2018. Natural gas liquids production for the year did not decline to the same extent as Bonavista's other products mainly due to new well production growth from production brought online during the first half of 2019 and the fourth quarter of 2018 that was focused on liquids rich development in the West Central core area. This focus on the most economic natural gas liquids development was offset by a reduction in new well production in the second half of 2019 and scheduled and unscheduled turnaround activity which resulted in some production being diverted to less efficient processing facilities reducing overall natural gas liquids recoveries. Oil production decreased 19% to 1,804 bbls per day for the year ended December 31, 2019 compared to 2,221 bbls per day for the same period of 2018, for similar reasons as noted above.

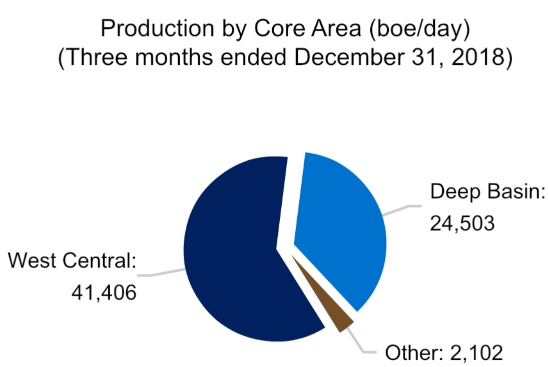


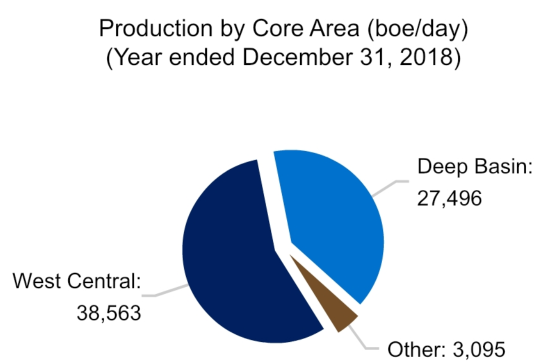
The following table sets forth Bonavista's production (boe per day) by core area for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
West Central	**41,646**	41,406	1 %	**39,269**	38,563	2 %
Deep Basin	**19,012**	24,503	(22)%	**21,926**	27,496	(20)%
Other	**2,265**	2,102	8 %	**2,162**	3,095	(30)%
Total oil equivalent	**62,923**	68,011	(7)%	**63,357**	69,154	(8)%









Production revenues

The following table sets forth Bonavista's production revenues[1] by product category for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands)						
Natural gas	**56,431**	66,469	(15)%	**190,221**	236,333	(20)%
Natural gas liquids	**35,224**	50,813	(31)%	**140,350**	227,827	(38)%
Oil	**9,087**	7,020	29 %	**41,834**	50,807	(18)%
Total production revenues	**100,742**	124,302	(19)%	**372,405**	514,967	(28)%
% of production revenue:						
Natural gas (%)	**56%**	53%	3 %	**51%**	46%	5 %
Natural gas liquids and oil (%)	**44%**	47%	(3)%	**49%**	54%	(5)%

Note:

(1) Excludes the impact of financial instrument commodity contracts but includes all fixed price physical contracts.

For the three months ended December 31, 2019, production revenues, excluding the impact of financial instrument commodity contracts, decreased 19% to $100.7 million compared to $124.3 million for the same period of 2018. The decrease was due to a seven percent decrease in average production volumes coupled with a 12% decrease in commodity prices on a per boe basis. The decrease in natural gas and natural gas liquids prices was mainly due to those reasons noted above, while oil prices improved from the levels experienced in the fourth quarter, 2018 which saw the differentials widen further than normal with Canadian crude oil receiving much lower oil prices than under normal conditions. The primary factor behind the wide oil price differentials, experienced in the fourth quarter of 2018, was a growing supply of western Canadian oil production with takeaway capacity remaining unchanged with elevated inventories. In 2019, oil prices somewhat stabilized with a return to more balanced inventory levels.

For the year ended December 31, 2019, production revenues, excluding the impact of financial instrument commodity contracts, decreased 28% to $372.4 million compared to $515.0 million for the same period of 2018. The decrease was due to an eight percent decrease in average production volumes coupled with a 21% decrease in commodity prices on a per boe basis. The decrease in commodity prices was primarily a result of the collapse in western Canadian butane prices in late 2018 caused by volatile market conditions. In addition, North American propane prices, benchmarked at Conway and Mt. Belvieu, dropped significantly in 2019 resulting from an abundance of supply on the continent. Due to these conditions, Bonavista's natural gas liquids pricing eroded significantly under the terms of the new contract year with purchasers of natural gas liquids products which commenced on April 1, 2019. During 2019, natural gas prices were also challenged due to limited natural gas export options, significant maintenance on NOVA Gas Transmission Ltd. ("NGTL") and a narrowing of the premium for natural gas production diversified beyond AECO in the latter half of the year to US Midwest and Dawn markets as a result of overall natural gas supply and demand fundamentals.

Commodity Prices

The following table outlines the average benchmark prices and foreign exchange rates for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
Average benchmark index prices:						
Natural gas - AECO 5A daily index ($/gj)	**2.35**	1.48	59 %	**1.67**	1.42	18 %
Natural gas - AECO 7A monthly index ($/gj)	**2.21**	1.80	23 %	**1.54**	1.45	6 %
Natural gas - Empress daily index ($/gj)	**2.40**	3.89	(38)%	**2.37**	2.92	(19)%
Natural gas - NYMEX (US$/MMbtu)	**2.50**	3.64	(31)%	**2.63**	3.09	(15)%
Natural gas - Ventura (daily) (US$/MMbtu)	**2.15**	3.63	(41)%	**2.37**	2.96	(20)%
Natural gas - Dawn (daily) (US$/MMbtu)	**2.24**	3.79	(41)%	**2.40**	3.12	(23)%
Propane - Conway (US/gal)	**0.47**	0.69	(32)%	**0.47**	0.72	(35)%
Propane - Mont Belvieu (US/gal)	**0.50**	0.80	(38)%	**0.54**	0.88	(39)%
Butane - Mont Belvieu non-TET (US/gal)	**0.73**	0.92	(21)%	**0.68**	1.05	(35)%
Light oil - MSW (Mixed Sweet) Edmonton ($/bbl)	**68.10**	42.70	59 %	**69.21**	70.92	(2)%
CDN$/US$ exchange rate	**1.3200**	1.3215	— %	**1.3269**	1.2962	2 %

Canadian natural gas prices are mainly influenced by North American supply and demand fundamentals which can be impacted by a number of factors, including, but not limited to: weather-related conditions in key consuming natural gas markets, competition from alternative energy sources, changing demographics, economic growth or contraction, gas storage levels, net import and export markets, pipeline takeaway capacity, and drilling and completion rates and efficiencies in extracting natural gas from North American natural gas basins. AECO natural gas prices throughout the first nine months of 2019 continued to receive a disproportionate discount when compared to other benchmark prices, primarily due to limited infrastructure and egress solutions out of the western Canadian natural gas basins. In the final quarter of the year, AECO did show signs of improvement as a result of improved access to natural gas storage facilities and improved supply and demand fundamentals ahead of the winter heating season. To mitigate Bonavista's exposure to volatile AECO pricing, Bonavista has engaged in an active market diversification strategy. Through this market diversification strategy, Bonavista has entered into various gas marketing and transportation arrangements to diversify and gain exposure to alternative natural gas markets in North America.

Worldwide supply and demand factors are the primary determinant in the benchmark prices for crude oil; however, regional market and transportation issues also influence prices. Bonavista generally compares its oil price to the West Texas Intermediate (WTI) benchmark price, which is priced at Cushing, Oklahoma and the Mixed Sweet Blend (MSW) benchmark price, which is priced at Edmonton, Alberta. The differential between the WTI oil price and MSW price can widen due to a number of factors, including, but not limited to: maintenance at North American refineries, domestic production, inventory levels and a lack of pipeline infrastructure connecting to key consuming oil markets. In 2019, the differentials narrowed from the wide differentials experienced in the fourth quarter of 2018, largely as a result of the Government of Alberta's curtailment limits and increased takeaway capacity by rail.

The following table sets forth Bonavista's physical and financial natural gas sales portfolio based on delivery point for the three months and year ended December 31:

	Three months ended December 31, 2019	Three months ended December 31, 2018
(% of natural gas production)		
AECO physical spot price deliveries	**11%**	20%
AECO physical fixed and financial price sales contracts	**59%**	56%
Dawn physical deliveries	**15%**	14%
US Midwest physical deliveries	**15%**	10%

	Year ended December 31, 2019	Year ended December 31, 2018
(% of natural gas production)		
AECO physical spot price deliveries	**17%**	18%
AECO physical fixed and financial price sales contracts	**54%**	60%
Dawn physical deliveries	**15%**	13%
US Midwest physical deliveries	**14%**	9%

The following table sets forth Bonavista's production revenues per boe, including realized gains and losses on financial instrument commodity contracts, for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
Natural gas ($/mcf):						
Production revenues(1)	**2.36**	2.58	(9)%	**1.96**	2.18	(10)%
Realized gains(2)	**0.03**	0.33	(91)%	**0.36**	0.60	(40)%
	2.39	2.91	(18)%	**2.32**	2.78	(17)%
Natural gas liquids ($/bbl):						
Production revenues(1)	**21.27**	28.87	(26)%	**22.41**	35.94	(38)%
Realized gains (losses)(2)	**6.07**	(3.88)	256 %	**2.56**	(6.64)	139 %
	27.34	24.99	9 %	**24.97**	29.30	(15)%
Oil ($/bbl):						
Production revenues(1)	**62.23**	36.21	72 %	**63.54**	62.68	1 %
Realized losses(2)	**(1.72)**	(7.74)	(78)%	**(2.07)**	(9.61)	(78)%
	60.51	28.47	113 %	**61.47**	53.07	16 %
Total ($/boe):						
Production revenues(1)	**17.40**	19.87	(12)%	**16.10**	20.40	(21)%
Realized gains(2)	**1.83**	0.04	4,475 %	**2.16**	0.64	238 %
	19.23	19.91	(3)%	**18.26**	21.04	(13)%

Notes:

(1) Excludes the impact of financial instrument commodity contracts but includes all fixed price physical contracts.
(2) Reference to realized gains (losses) on financial instrument commodity contracts.

Natural gas prices, excluding the impact of financial instrument commodity contracts, decreased nine percent to $2.36 per mcf for the three months ended December 31, 2019 compared to $2.58 per mcf for the same period of 2018. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, decreased 26% to $21.27 per bbl for the three months ended December 31, 2019 compared to $28.87 per bbl for the same period of 2018. Oil prices, excluding the impact of financial instrument commodity contracts, increased 72% to $62.23 per bbl for the three months ended December 31, 2019 compared to $36.21 per bbl for the same period of 2018.

Natural gas prices, excluding the impact of financial instrument commodity contracts, decreased 10% to $1.96 per mcf for the year ended December 31, 2019 compared to $2.18 per mcf for the same period of 2018. Natural gas liquids prices, excluding the impact of financial instrument commodity contracts, decreased 38% to $22.41 per bbl for the year ended December 31, 2019 compared to $35.94 per bbl for the same period of 2018. Oil prices, excluding the impact of financial instrument commodity contracts, increased slightly to $63.54 per bbl for the year ended December 31, 2019 compared to $62.68 per bbl for the same period of 2018.

Consistent with Bonavista's objectives to preserve financial flexibility and maintain a strong financial position through the management of its capital structure, financial instrument commodity contracts have partially mitigated Bonavista's exposure to the volatile commodity price environment. For the three months ended December 31, 2019, a gain of $10.6 million was realized on Bonavista's financial instrument commodity contracts compared to a realized gain of $0.3 million in the same period of 2018. Similarly, for the year ended December 31, 2019, a gain of $49.9 million was realized on Bonavista's financial instrument commodity contracts compared to a realized gain of $16.1 million in the same period of 2018.

For the three months ended December 31, 2019, natural gas prices, including the impact of financial instrument commodity contracts, decreased 18% to $2.39 per mcf compared to $2.91 per mcf for the same period of 2018. Natural gas liquids prices, including the impact of financial instrument commodity contracts, increased nine percent to $27.34 per bbl for the three months ended December 31, 2019 compared to $24.99 per bbl realized for the same period of 2018. Oil prices, including the impact of financial instrument commodity contracts, increased 113% to $60.51 per bbl for the three months ended December 31, 2019 compared to $28.47 per bbl realized for the same period of 2018.

For the year ended December 31, 2019, natural gas prices, including the impact of financial instrument commodity contracts, decreased 17% to $2.32 per mcf compared to $2.78 per mcf for the same period of 2018. Natural gas liquids prices, including the impact of financial instrument commodity contracts, decreased 15% to $24.97 per bbl for the year ended December 31, 2019 compared to $29.30 per bbl realized for the same period of 2018. Oil prices, including the impact of financial instrument commodity contracts, increased 16% to $61.47 per bbl for the year ended December 31, 2019 compared to $53.07 per bbl realized for the same period of 2018.

Risk management activities

Bonavista is exposed to commodity price risk as prices received for its natural gas, natural gas liquids and oil production fluctuate. Commodity prices fluctuate as a result of a number of local and global factors including, supply and demand, inventory levels, weather patterns, pipeline transportation constraints, political stability and economic factors. Bonavista mitigates a portion of the commodity price risk through the use of various financial instrument commodity contracts and physical delivery sales contracts. Bonavista's policy is to enter into commodity price contracts when considered appropriate to a maximum of 70% of forecasted production volumes for the subsequent twelve month period, 60% in years two and three and 25% in years four and five, provided that no more than 80% of forecasted production volumes from any one product (where natural gas and ethane are considered as one product, propane is considered to be its own product and butane, condensate and oil are considered one product) may be hedged, or in the case of electricity, 60% of Bonavista's forecasted net consumption. The term of any commodity hedge executed will be limited to no more than five calendar years subsequent to the current calendar year. Bonavista's management regularly reviews this policy to reflect changes in market conditions.

Commodity price risk

Commodity prices for natural gas, natural gas liquids and oil are impacted not only by global economic events that dictate the levels of supply and demand, but also by the relationship between the CDN and US currency. Swaps and costless collars are primarily entered into, which limits Bonavista's exposure to volatility in commodity prices while in the case of costless collars allows for the participation in some of the commodity price increases.

At December 31, 2019, Bonavista had entered into the following costless collars to sell oil:

Volume		Average Price	Contract	Term
Oil contracts				
500	bbls/d	CDN $67.50 - CDN $73.01	WTI - Costless Collar	January 1, 2020 - December 31, 2020

At December 31, 2019, Bonavista had entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
Natural gas				
30,000	gj/d	CDN $2.01	AECO - Swap	January 1, 2020 - March 31, 2020
10,000	gj/d	CDN $1.67	AECO - Swap	January 1, 2020 - December 31, 2020
65,000	gj/d	CDN $1.53	AECO - Swap	April 1, 2020 - October 31, 2020
15,000	gj/d	CDN $1.81	AECO - Swap	January 1, 2021 - December 31, 2021
35,000	gj/d	CDN $1.67	AECO - Swap	April 1, 2021 - October 31, 2021
30,000	mmbtu/d	US ($1.15)	AECO - Basis Swap	January 1, 2020 - March 31, 2020
10,000	mmbtu/d	US ($0.98)	AECO - Basis Swap	January 1, 2020 - December 31, 2021
30,000	mmbtu/d	US ($1.36)	AECO - Basis Swap	April 1, 2020 - October 31, 2020
20,000	mmbtu/d	US ($1.16)	AECO - Basis Swap	November 1, 2020 - March 31, 2021
40,000	mmbtu/d	US ($1.29)	AECO - Basis Swap	April 1, 2021 - October 31, 2021
10,000	mmbtu/d	US ($1.16)	AECO - Basis Swap	November 1, 2021 - March 31, 2022
30,000	mmbtu/d	US ($1.36)	AECO - Basis Swap	April 1, 2022 - October 31, 2022
15,000	mmbtu/d	US ($0.08)	DAWN - Basis Swap	January 1, 2020 - December 31, 2021
20,000	mmbtu/d	US ($0.16)	CHICAGO - Basis Swap	January 1, 2020 - March 31, 2024
10,000	mmbtu/d	US $2.84	NYMEX - Swap	January 1, 2020 - March 31, 2020
10,000	mmbtu/d	US $2.77	NYMEX - Swap	January 1, 2020 - October 31, 2020
35,000	mmbtu/d	US $2.75	NYMEX - Swap	January 1, 2020 - December 31, 2020
5,000	mmbtu/d	US $2.27	NYMEX - Swap	April 1, 2020 - October 31, 2020
10,000	gj/d	CDN $1.75	AECO - Sold Call	January 1, 2020 - December 31, 2020
10,000	gj/d	CDN $1.80	AECO - Sold Call	January 1, 2021 - December 31, 2021
10,000	mmbtu/d	US $3.75	NYMEX - Sold Call	January 1, 2020 - December 31, 2021
Natural gas liquids				
250	bbls/d	US $34.86	MTB BT - Swap	January 1, 2020 - December 31, 2020
250	bbls/d	US $34.86	MTB BT - Swap	April 1, 2020 - December 31, 2020
Oil				
750	bbls/d	CDN $80.57	WTI - Swap	January 1, 2020 - March 31, 2020
1,750	bbls/d	CDN $79.06	WTI - Swap	January 1, 2020 - December 31, 2020
750	bbls/d	CDN $77.14	WTI - Swap	January 1, 2021 - December 31, 2021
1,000	bbls/d	CDN $90.00	WTI - Sold Call	January 1, 2020 - December 31, 2020
1,250	bbls/d	US $55.68	WTI - Sold Call	January 1, 2020 - December 31, 2020

Subsequent to December 31, 2019, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
5,000	gj/d	CDN $1.68	AECO - Swap	April 1, 2020 - October 31, 2020
15,000	gj/d	CDN $1.71	AECO - Swap	April 1, 2020 - March 31, 2021
15,000	gj/d	CDN $1.32	AECO - Swap	November 1, 2020 - March 31, 2021
5,000	mmbtu/d	US $2.29	NYMEX - Swap	April 1, 2020 - October 31, 2020
250	bbls/d	CDN $76.00	WTI - Swap	April 1, 2020 - March 31, 2021

As at December 31, 2019, the fair value recorded on the consolidated statement of financial position for these financial instrument commodity contracts was a net liability of $12.9 million compared to a net asset of $69.2 million at December 31, 2018. Of the $12.9 million net liability balance at December 31, 2019, a net liability of $1.1 million relates to financial instrument commodity contracts with term dates within one year and a net liability of $11.8 million relates to financial instrument commodity contracts with term dates beyond one year. Of the $69.2 million net asset balance at December 31, 2018, a net asset of $54.5 million relates to financial instrument commodity contracts with term dates within one year and a net asset of $14.7 million relates to financial instrument commodity contracts with term dates beyond one year.

For the three months ended December 31, 2019, the financial instrument commodity contracts in place under Bonavista's risk management program resulted in a net loss of $24.7 million, consisting of a realized gain of $10.6 million and an unrealized loss of $35.3 million. The realized gain of $10.6 million consisted of a $0.8 million gain on natural gas commodity derivative contracts, a $10.1 million gain on natural gas liquids commodity derivative contracts and a $0.3 million loss on oil commodity derivative contracts. For the same period of 2018, the financial instrument commodity contracts in place resulted in a net gain of $140.1 million, consisting of a realized gain of $0.3 million and an unrealized gain of $139.8 million. The realized gain of $0.3 million consisted of an $8.6 million gain on natural gas commodity derivative contracts, a $6.8 million loss on natural gas liquids commodity derivative contracts and a $1.5 million loss on oil commodity derivative contracts.

For the year ended December 31, 2019, the financial instrument commodity contracts in place under Bonavista's risk management program resulted in a net loss of $32.2 million, consisting of realized gains of $49.9 million and an unrealized loss of $82.1 million. The realized gain of $49.9 million consisted of a $35.3 million gain on natural gas commodity derivative contracts, a $16.0 million gain on natural gas liquids commodity derivative contracts and a $1.4 million loss on oil commodity derivative contracts. For the same period of 2018, the financial instrument commodity contracts in place resulted in a net gain of $59.1 million, consisting of a realized gain of $16.1 million and an unrealized gain of $43.0 million. The realized gain of $16.1 million consisted of a $66.0 million gain on natural gas commodity derivative contracts, a $42.1 million loss on natural gas liquids commodity derivative contracts and a $7.8 million loss on oil commodity derivative contracts.

The following table sets forth Bonavista's realized and unrealized gains and losses on financial instrument commodity contracts for the three months and year ended December 31:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ thousands)				
Natural gas	**781**	8,603	**35,274**	65,977
Natural gas liquids	**10,055**	(6,835)	**16,026**	(42,104)
Oil	**(253)**	(1,500)	**(1,360)**	(7,790)
Realized gains on financial instrument commodity contracts	**10,583**	268	**49,940**	16,083
Unrealized gains (losses) on financial instrument commodity contracts	**(35,293)**	139,841	**(82,106)**	43,014
Net gain (loss) on financial instrument commodity contracts	**(24,710)**	140,109	**(32,166)**	59,097

Bonavista's financial instrument commodity contracts are sensitive to commodity price volatility. The following table highlights the approximate impact that changes in the fair value of the financial instrument commodity contracts would have on net loss and comprehensive loss at December 31, 2019 with changes to the underlying commodity prices.

	Commodity Price Sensitivity	
($ thousands)		
	Increase $0.10	Decrease $0.10
Natural Gas Commodity Contracts	(10,708)	10,708
	Increase $1.00	Decrease $1.00
Natural Gas Liquids Commodity Contracts	(153)	153
	Increase $1.00	Decrease $1.00
Oil Commodity Contracts	(722)	722

In addition to these financial instrument commodity contracts in place, Bonavista also entered into the following fixed price physical contracts to sell natural gas as at December 31, 2019:

Volume	Price	Contract	Term
30,000 gj/d	CDN $2.13	AECO	January 1, 2020 - March 31, 2020(1)
10,000 gj/d	CDN $1.75	AECO	January 1, 2020 - December 31, 2020(2)
10,000 gj/d	CDN $2.02	AECO	January 1, 2022 - December 31, 2023(2)

Note:

(1) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 30,000 gj/d on the last trade date of each month for the duration of the contract.
(2) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 10,000 gj/d on the last trade date of each month for the duration of the contract.

Foreign exchange risk

Bonavista is exposed to foreign currency fluctuations as natural gas, natural gas liquids and oil prices are referenced to US dollar denominated prices. Bonavista has mitigated some of this foreign exchange risk by entering into fixed CDN dollar natural gas, natural gas liquids and oil swaps and collars as outlined in the commodity price risk section above. In addition, Bonavista has US dollar denominated senior unsecured notes and interest obligations of which future cash repayments are directly impacted by the CDN dollar to the US dollar exchange rate. To fix the foreign exchange rate on a portion of the US dollar denominated senior unsecured notes, Bonavista has entered into the following contracts to purchase US dollars at predetermined rates on settlement dates that coincide with Bonavista's US dollar debt repayment commitments:

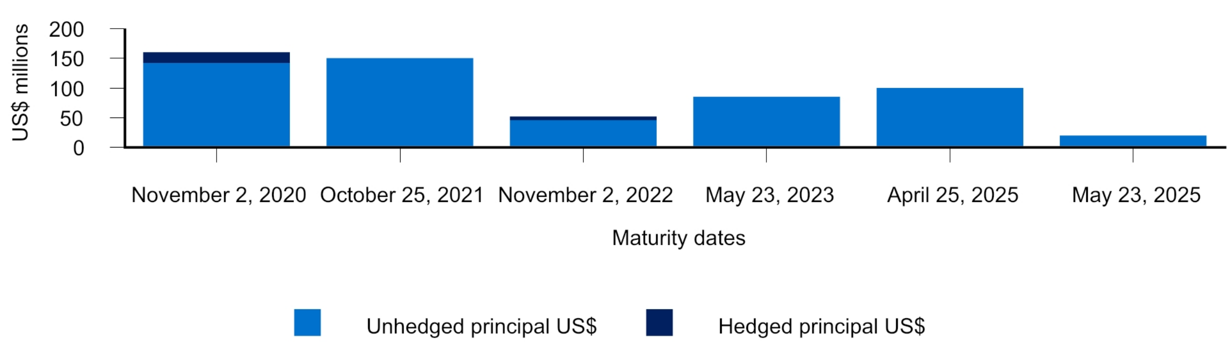
Settlement date	Contract	Notional US$	CDN$/US$
November 2, 2020	US$ purchased forward	$17,800,000	1.3297
November 2, 2022	US$ purchased forward	$5,500,000	1.3318

During the fourth quarter of 2019, Bonavista monetized the value in certain foreign exchange contracts for proceeds of $5.9 million. The transactions monetized in advance of their maturity date included:

Settlement date	Contract	Notional US$	CDN$/US$
November 2, 2020	US$ purchased forward	$142,200,000	1.3018
October 25, 2021	US$ purchased forward	$150,000,000	1.2991
November 2, 2022	US$ purchased forward	$44,500,000	1.2975
May 23, 2023	US$ purchased forward	$40,000,000	1.2974

Below is an illustration of the notional amount of Bonavista's foreign exchange contracts as compared to the principal repayment of its US denominated senior unsecured notes at maturity:

US Denominated Senior Unsecured Notes by Maturity Date



As at December 31, 2019, the fair value recorded on the consolidated statement of financial position for these financial instrument contracts was a net liability of $0.7 million compared to a net asset of $18.4 million at December 31, 2018. Of the $0.7 million net liability at December 31, 2019, a net liability of $542,000 relates to financial instrument contracts with term dates within one year and $138,000 relates to financial instrument contracts with term dates beyond one year. In the comparison year the fair value of those instruments in place at December 31, 2018 was a net asset of $18.4 million, of which a net asset of $1.2 million related to financial instrument contracts with term dates within one year and a net asset of $17.2 million related to financial instrument contracts with term dates beyond one year.

For the three months ended December 31, 2019, an unrealized loss of $10.3 million on financial instrument contracts was recorded, compared to an unrealized gain of $28.5 million for the same period of 2018. The unrealized loss for the three months ended December 31, 2019, resulted from a stronger CDN dollar relative to the US dollar, which at December 31, 2019 was $1.2990 CDN$/US$ compared to the September 30, 2019 rate of $1.3241 CDN$/US$, as well as the monetization of certain financial instrument contracts in the fourth quarter of 2019.

Similarly, for the year ended December 31, 2019, an unrealized loss of $19.1 million on financial instrument contracts was recorded, compared to an unrealized gain of $37.7 million for the same prior period of 2018. The unrealized loss for the year ended December 31, 2019, resulted from a stronger CDN dollar relative to the US dollar, which at December 31, 2019 was $1.2990 CDN$/US$ compared to the December 31, 2018 rate of $1.3641 CDN$/US$, as well as the monetization of certain financial instrument contracts in the fourth quarter of 2019.

Bonavista's financial instrument contracts are sensitive to changes in the CDN dollar to the US dollar exchange rate. Holding all other variables constant, a $0.01 change in the CDN$/US$ exchange rate at December 31, 2019 would have had an impact of approximately $0.3 million on net loss and comprehensive loss.

Royalties

The following table sets forth Bonavista's royalties(1) by product category for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
Natural gas ($/mcf):						
Royalties	**(0.07)**	(0.17)	(59)%	**(0.15)**	(0.12)	25 %
% of Production revenues(2)	**(3.2)%**	(6.5)%	(3.3)%	**(7.5)%**	(5.5)%	2.0 %
Natural gas liquids ($/bbl):						
Royalties	**4.05**	5.05	(20)%	**4.20**	6.47	(35)%
% of Production revenues(2)	**19.0 %**	17.5 %	1.5 %	**18.7 %**	18.0 %	0.7 %
Oil ($/bbl):						
Royalties	**8.25**	4.96	66 %	**7.98**	7.90	1 %
% of Production revenues(2)	**13.3 %**	13.7 %	(0.4)%	**12.6 %**	12.6 %	— %
Total:						
Royalties ($ thousands)	**6,123**	5,544	10 %	**17,377**	34,360	(49)%
Royalties ($/boe)	**1.06**	0.89	19 %	**0.75**	1.36	(45)%
% of Production revenues(2)	**6.1 %**	4.5 %	1.6 %	**4.7 %**	6.7 %	(2.0)%

Notes:

(1) Bonavista's royalty obligations are primarily with the Government of Alberta.
(2) % of production revenues excludes realized gains and losses on financial instrument commodity contracts.

For the three months ended December 31, 2019 royalties increased 10% to $6.1 million from $5.5 million for the same period of 2018. Royalties as a percentage of total production revenues were 6.1% for the three months ended December 31, 2019 compared to 4.5% for the three months ended December 31, 2018. The increase in royalties on an absolute basis and as a percentage of production revenues for the three months ended December 31, 2019, was primarily the result of a decrease in prior period gas cost allowance credits as well as a reduction in Bonavista's average realized natural gas liquids price relative to the associated crown reference price on which royalty obligations are calculated. In addition, in the fourth quarter of 2019, Bonavista's natural gas liquids revenue had a higher weighting towards condensate revenues which carries a higher percentage royalty rate relative to other natural gas liquids products.

Natural gas royalties as a percentage of natural gas production revenues for the three months ended December 31, 2019 was a recovery of 3.2% compared to a recovery of 6.5% for the three months ended December 31, 2018. Natural gas royalties were in a recovery position in both 2018 and 2019 largely as a result of gas cost allowance credits being significantly more than gas royalties due to depressed natural gas pricing. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the three months ended December 31, 2019 were 19.0% compared to 17.5% for the same period of 2018, for similar reasons as noted above. Oil royalties as a percentage of oil production revenues for the three months ended December 31, 2019 were 13.3% compared to 13.7% for the three months ended December 31, 2018.

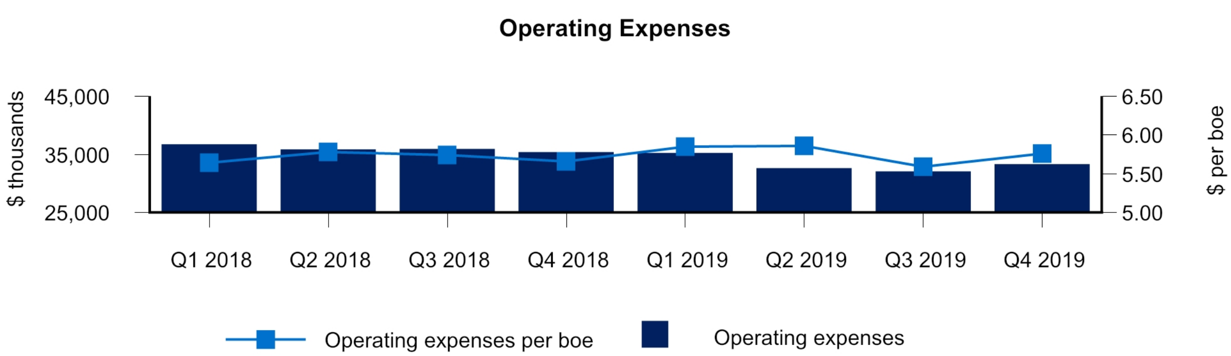
For the year ended December 31, 2019 royalties decreased 49% to $17.4 million from $34.4 million for the same period of 2018. Royalties as a percentage of production revenues were 4.7% for the year ended December 31, 2019 compared to 6.7% for the year ended December 31, 2018. The decrease in royalties as a percentage of production revenues for the year ended December 31, 2019, was due primarily to a 28% decrease in production revenues and lower natural gas royalties incurred primarily as a result of prior period royalty adjustments, the impact of a higher current year gas cost allowance credits and stronger realized prices relative to reference crown pricing on which royalty obligations are based.

Natural gas royalties as a percentage of natural gas production revenues for the year ended December 31, 2019 was a recovery of 7.5% compared to a recovery of 5.5% for the year ended December 31, 2018, due to prior period gas cost allowance credits and prior period adjustments to royalty obligations on freehold lands. Natural gas liquids royalties as a percentage of natural gas liquids production revenues for the year ended December 31, 2019 was 18.7% compared to 18.0% for the same period of 2018. Natural gas liquids royalties were higher as a percentage of production revenues, due to a change in the composition of Bonavista's natural gas liquids production revenues. This resulted in a higher condensate revenue weighting leading to a higher overall royalty rate. Oil royalties as a percentage of oil production revenues were unchanged at 12.6% for the year ended December 31, 2019 and December 31, 2018.

Operating expenses

The following table sets forth Bonavista's operating expenses for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands, except for per boe amounts)						
Operating expenses	**33,333**	35,383	(6)%	**133,312**	143,935	(7)%
Per boe	**5.76**	5.66	2 %	**5.76**	5.70	1 %



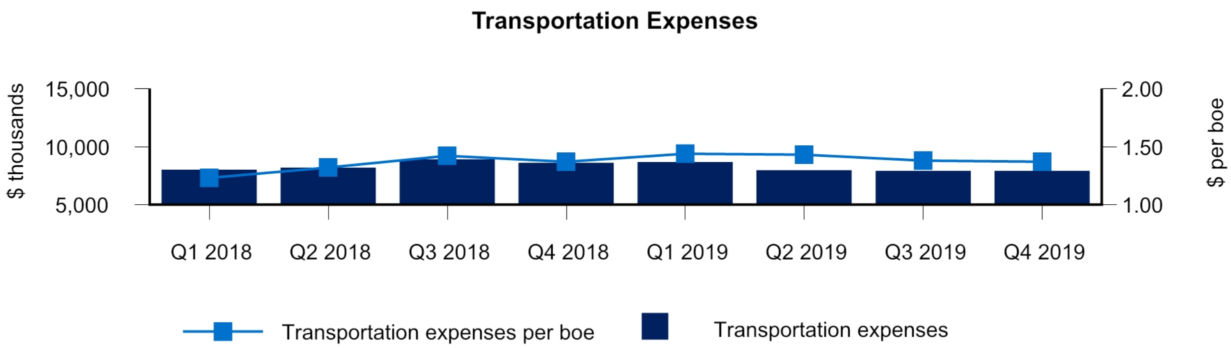
For the three months ended December 31, 2019, operating expenses decreased six percent to $33.3 million compared to $35.4 million for the same period of 2018, primarily as a result of a seven percent decrease in production volumes. On a per boe basis, operating expenses increased two percent to $5.76 per boe for the three months ended December 31, 2019 compared to $5.66 per boe for the same period of 2018. The increase in operating expenses on a per boe basis was largely due the temporary shut-in of wells in response to low natural gas prices, natural declines in well production in excess of new well production growth and the acquisition of assets occurring in the fourth quarter that currently have higher operating expenses per boe than Bonavista's corporate average. The decreases in production volumes impact operating expenses on a per boe basis as fixed costs are spread amongst fewer producing barrels of oil equivalent.

For the year ended December 31, 2019, operating expenses decreased seven percent to $133.3 million compared to $143.9 million for the same period of 2018, primarily as a result of an eight percent decrease in production volumes offset by the seasonality impact of prolonged winter conditions early in 2019 and significant turnaround activity. On a per boe basis, operating expenses increased slightly to $5.76 per boe for the year ended December 31, 2019 compared to $5.70 per boe for the same period of 2018. The modest increase in operating expenses on a per boe basis was largely due to the temporary shut-in of wells in response to low natural gas prices and significant turnaround activity in the second quarter of 2019 and the property acquisition occurring in the fourth quarter of 2019. These production curtailments impact operating expenses on a per boe basis as fixed costs are spread amongst fewer producing barrels of oil equivalent. To mitigate the impact of the scheduled turnaround activity Bonavista diverted production in the second quarter to certain third-party facilities with higher cost structures. In addition, prolonged winter conditions in the first quarter of the year led to higher expenses for compression and chemical services.

Transportation expenses

The following table sets forth Bonavista's transportation expenses for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands, except for per boe, per bbl, and per mcf amounts)						
Transportation expenses	**7,929**	8,602	(8)%	**32,490**	33,728	(4)%
Per boe	**1.37**	1.37	— %	**1.40**	1.34	4 %
Natural gas ($/mcf)	**0.31**	0.30	3 %	**0.30**	0.28	7 %
Natural gas liquids ($/bbl)	**0.23**	0.45	(49)%	**0.41**	0.44	(7)%
Oil ($/bbl)	**0.88**	0.74	19 %	**0.82**	0.76	8 %



Transportation expenses for the three months ended December 31, 2019, decreased eight percent to $7.9 million compared to $8.6 million for the same period of 2018, largely as a result of a seven percent decrease in production volumes. On a per boe basis, transportation expenses for the three months ended December 31, 2019 and December 31, 2018 were unchanged at $1.37 per boe.

Transportation expenses for the year ended December 31, 2019, decreased four percent to $32.5 million compared to $33.7 million for the same period of 2018, largely as a result of an eight percent decrease in production volumes. On a per boe basis, transportation expenses for the year ended December 31, 2019 increased four percent to $1.40 per boe from $1.34 per boe for the comparable period of 2018. During the second quarter of 2019, incremental trucking costs were experienced relating to road bans and higher wait times as a result of unseasonably wet spring weather conditions and infrastructure constraints. Further, natural gas transportation expenses were impacted by firm service obligations where transportation restrictions occurred on the NGTL system which reduced utilization but increased firm transportation per unit charges on certain production volumes. Partially offsetting these higher transportation rates was the impact of changes to natural gas liquids contract terms including custody transfer points, effective for the new contract year commencing April 1, 2019.

Operating Netback and Operating Margin

The following tables set forth Bonavista's operating netback[1] per boe and operating margin[1] by core area for the three months and year ended December 31:

	Three months ended December 31, 2019			Three months ended December 31, 2018		
	West Central	Deep Basin	Total[3]	West Central	Deep Basin	Total[3]
Production revenues	**17.69**	**17.44**	**17.40**	20.22	19.90	19.87
Realized gains on financial instrument commodity contracts[2]	**—**	**—**	**1.83**	—	—	0.04
	17.69	**17.44**	**19.23**	20.22	19.90	19.91
Royalties	**1.42**	**0.25**	**1.06**	1.27	0.48	0.89
Operating expenses	**6.36**	**3.47**	**5.76**	5.82	4.34	5.66
Transportation expenses	**1.13**	**1.98**	**1.37**	0.95	2.15	1.37
Operating netback	**8.78**	**11.74**	**11.04**	12.18	12.93	11.99
Operating margin	**50%**	**67%**	**57%**	60%	65%	60 %

	Year ended December 31, 2019			Year ended December 31, 2018		
	West Central	Deep Basin	Total[3]	West Central	Deep Basin	Total[3]
Production revenues	**16.43**	**16.23**	**16.10**	21.94	19.00	20.40
Realized gains on financial instrument commodity contracts[2]	**—**	**—**	**2.16**	—	—	0.64
	16.43	**16.23**	**18.26**	21.94	19.00	21.04
Royalties	**0.96**	**0.41**	**0.75**	1.86	0.78	1.36
Operating expenses	**6.06**	**4.33**	**5.76**	6.30	4.01	5.70
Transportation expenses	**1.08**	**2.06**	**1.40**	0.99	1.91	1.34
Operating netback	**8.33**	**9.43**	**10.35**	12.79	12.30	12.64
Operating margin	**51%**	**58%**	**57%**	58%	65%	60 %

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. Refer to the section entitled "Non-GAAP Measures".
(2) Amounts are not allocated by area.
(3) Total includes amounts recorded in the British Columbia and Saskatchewan areas that are not inclusive in the West Central and Deep Basin core areas.

Bonavista's operating netback for the three months ended December 31, 2019, decreased eight percent to $11.04 per boe compared to $11.99 per boe for the same period of 2018. The decrease in Bonavista's operating netback on a per boe basis was primarily due to a three percent decrease in production revenues (including realized gains on financial instrument commodity contracts), a 19% increase in royalty expenses and a two percent increase in operating expenses. Bonavista's operating margin also decreased three percent to 57% for the three months ended December 31, 2019 compared to 60% for the three months ended December 31, 2018, for those reasons noted above.

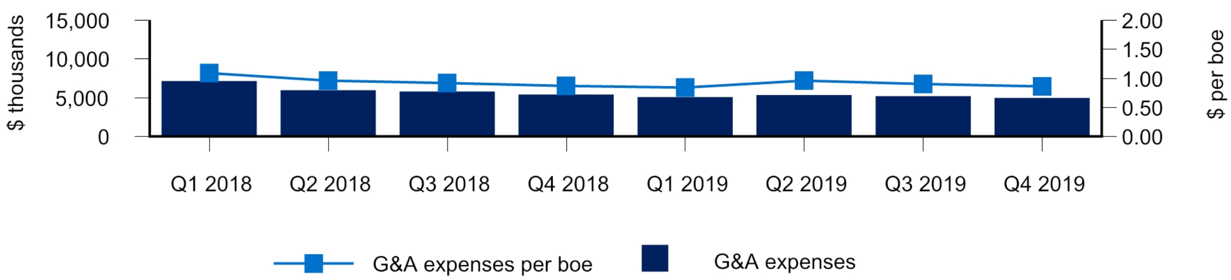
Bonavista's operating netback for the year ended December 31, 2019, decreased 18% to $10.35 per boe compared to $12.64 per boe for the same period of 2018. The decrease in Bonavista's operating netback on a per boe basis was primarily due to a 13% decrease in production revenues (including realized gains on financial instrument commodity contracts) and a four percent increase in transportation expenses, partially offset by a 45% decrease in royalty expenses. Bonavista's operating margin also decreased three percent to 57% for the year ended December 31, 2019 compared to 60% for the year ended December 31, 2018, for those reasons noted above.

General and administrative expenses

The following table sets forth Bonavista's general and administrative expenses for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands, except for per boe amounts)						
General and administrative expenses	**4,961**	5,413	(8)%	**20,577**	24,291	(15)%
Per boe	**0.86**	0.87	(1)%	**0.89**	0.96	(7)%

General and Administrative (G&A) Expenses



For the three months ended December 31, 2019, general and administrative expenses, after overhead recoveries, decreased eight percent to $5.0 million compared to $5.4 million for the same period of 2018. On a per boe basis, general and administrative expenses for the three months ended December 31, 2019 and December 31, 2018 were relatively unchanged at $0.86 per boe and $0.87 per boe respectively. For the year ended December 31, 2019, general and administrative expenses, after overhead recoveries, decreased 15% to $20.6 million compared to $24.3 million of the same period of 2018. Similarly, on a per boe basis, general and administrative expenses decreased seven percent to $0.89 per boe for the year ended December 31, 2019 compared to $0.96 per boe for the same period of 2018.

The decrease in general and administrative expenses on an absolute and per boe basis was primarily due to human resource attrition and the adoption of IFRS 16 *Leases* whereby a right-of-use asset and lease liability was recognized for Bonavista's head office lease. As such rent expense for the year ended December 31, 2019 was $3.5 million lower in comparison to 2018. As Bonavista adopted IFRS 16 using the modified retrospective approach, comparative information in the Corporation's financial statements has not been restated. In addition to the impact of IFRS 16, cost saving initiatives over the last five years have continued to result in reductions in Bonavista's administrative cost structure and discretionary spending.

Net financing costs

The following table sets forth net financing costs for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands, except for per boe amounts)						
Interest expense(1)	**9,011**	8,553	5 %	**34,938**	35,141	(1) %
Per boe	**1.56**	1.37	14 %	**1.51**	1.39	9 %
Net finance costs	**3,611**	22,958	(84) %	**23,131**	66,450	(65) %
Per boe	**0.62**	3.67	(83) %	**1.00**	2.63	(62) %

Note:

(1) Interest on bank credit facility and senior unsecured notes.

For the three months ended December 31, 2019, net finance costs decreased 84% to $3.6 million compared to net finance costs of $23.0 million for the same period of 2018. Similarly, for the three months ended December 31, 2019, net finance costs on a per boe basis were lower at $0.62 per boe compared to net finance costs of $3.67 per boe for the three months ended December 31, 2018. The decrease in net finance costs, on an absolute and per boe basis, can be largely attributed to fluctuations in the CDN dollar to the US dollar exchange rate, impacting foreign exchange gains and losses associated with the revaluation of Bonavista's US denominated senior unsecured notes and unrealized gains and losses on Bonavista's financial instrument contracts. Further impacting the change in unrealized gains and losses on financial instrument contracts, was the fact that Bonavista monetized the value in certain foreign exchange contracts in the fourth quarter of 2019 and recorded a realized gain on financial instrument contracts of $5.9 million.

For the year ended December 31, 2019, net finance costs decreased 65% to $23.1 million compared to net finance costs of $66.5 million for the same period of 2018. Similarly, for the year ended December 31, 2019, net finance costs on a per boe basis were lower at $1.00 per boe compared to net finance costs of $2.63 per boe for the year ended December 31, 2018. The decrease in net finance costs, on an absolute and per boe basis, can be largely attributed to those reasons as noted above.

For the three months ended December 31, 2019, interest expense increased five percent to $9.0 million compared to interest expense of $8.6 million for the same period of 2018. The increase was primarily due to higher average borrowings on the bank credit facility, partially offset by lower interest payments on US denominated senior unsecured notes as a result a stronger CDN dollar to US dollar exchange rate used to recognize bi-annual interest payments. On a per boe basis interest expense increased 14% to $1.56 per boe for the three months ended December 31, 2019 compared to $1.37 per boe for the three months ended December 31, 2018, for those reasons noted above in addition to the impact of a seven percent decrease in production volumes.

For the year ended December 31, 2019, interest expense was relatively unchanged at $34.9 million compared to interest expense of $35.1 million for the same period of 2018. The modest decrease was primarily due to lower average borrowings on the bank credit facility throughout the first nine months of 2019. Despite the decrease in interest expense on an absolute basis, on a per boe basis interest expense increased nine percent to $1.51 per boe for the year ended December 31, 2019 compared to $1.39 per boe for the year ended December 31, 2018, due to the impact of an eight percent decrease in production volumes.

Cash Costs

The following table sets forth Bonavista's cash costs[1] on a per boe basis for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
Operating expenses	**5.76**	5.66	2 %	**5.76**	5.70	1 %
Transportation expenses	**1.37**	1.37	— %	**1.40**	1.34	4 %
General and administrative expenses	**0.86**	0.87	(1)%	**0.89**	0.96	(7)%
Interest expense	**1.56**	1.37	14 %	**1.51**	1.39	9 %
Cash costs	**9.55**	9.27	3 %	**9.56**	9.39	2 %

Note:

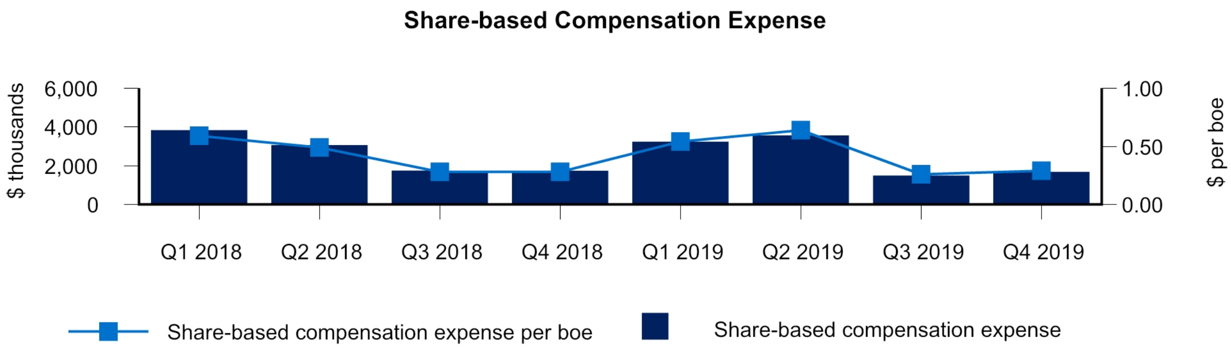
(1) Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Refer to the section entitled "Non-GAAP Measures".

Cash costs for the three months ended December 31, 2019, increased three percent to $9.55 per boe compared to $9.27 per boe for the same period of 2018. Similarly, cash costs for the year ended December 31, 2019, increased two percent to $9.56 per boe, compared to $9.39 per boe for the same period of 2018. Cash costs were slightly higher as a result of higher operating and interest expenses on a per boe basis with fixed costs spread amongst fewer producing barrels of oil equivalent.

Share-based compensation

The following table sets forth Bonavista's share-based compensation expense recognized for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands, except for per boe amounts)						
Share-based compensation expense	**1,680**	1,732	(3)%	**9,961**	10,381	(4)%
Per boe	**0.29**	0.28	4 %	**0.43**	0.41	5 %



Share-based compensation expense was relatively unchanged at $1.7 million for the three months ended December 31, 2019 and December 31, 2018. For the three months ended December 31, 2019 and December 31, 2018, $0.1 million of share-based compensation was capitalized to property, plant and equipment. Share-based compensation expense was $10.0 million for the year ended December 31, 2019 compared to $10.4 million for the comparative 2018 period. For the year ended December 31, 2019, $0.6 million of share-based compensation was capitalized in property, plant and equipment compared to $0.7 million in the same period of 2018. Although, there was an increase in the number of outstanding long-term incentive awards in 2019, share-based compensation expense was lower as the result of a lower valuation attributed to 2019 awards due to a decline in Bonavista's share price.The average grant price of awards issued in 2019 was $1.16 per award compared to an average price of $1.96 per award in 2018.

Bonavista adopted a deferred share unit ("DSU") plan primarily for non-management directors and non-executive officers, which entitles participants to receive cash, based on the share price of the Corporation's common shares on the payment date. Beginning in 2019, the Corporation's non-management directors will no longer participate in the Restricted Incentive Award Plan but will receive an annual grant of deferred share units and have the option to receive all or a portion of their Board and Committee compensation in the form of deferred share units instead of cash. Deferred share units vest immediately upon grant and can only be redeemed following the participants departure from the Corporation and must be redeemed prior to December 1st of the year following the departure date. The compensation liability resulting from the cash-settled DSUs granted during the year ended December 31, 2019 was $0.4 million, based on Bonavista's closing share price of $0.61 per share. There were no DSUs cash settled during the year ended December 31, 2019.

Depletion, depreciation, amortization and impairment

The following table sets forth Bonavista's depletion, depreciation, amortization and impairment expense recognized for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands, except for per boe amounts)						
Depletion, depreciation and amortization expense	**48,051**	56,177	(14) %	**206,967**	227,447	(9) %
Impairment expense	**14,323**	—	100 %	**292,323**	—	100 %
Depletion, depreciation, amortization and impairment expense	**62,374**	56,177	11 %	**499,290**	227,447	120 %
Per boe	**10.77**	8.98	20 %	**21.59**	9.01	140 %

For the three months ended December 31, 2019, depletion, depreciation, amortization and impairment expense increased 11% to $62.4 million from $56.2 million for the same period of 2018, due to a $14.3 million impairment charge partially offset by the seven percent decrease in production volumes on which depletion expense is based. On a per boe basis, depletion, depreciation, amortization and impairment expense was 20% higher at $10.77 per boe for the three months ended December 31, 2019 compared to $8.98 per boe for the same period of 2018.

For the year ended December 31, 2019, depletion, depreciation, amortization and impairment expense increased 120% to $499.3 million from $227.4 million for the same period of 2018. On a per boe basis, depletion, depreciation, amortization and impairment expense was 140% higher at $21.59 per boe for the year ended December 31, 2019 compared to $9.01 per boe for the same period of 2018. The increase in depletion, depreciation, amortization and impairment expense on an absolute and per boe basis was due to a $292.3 million impairment charge recorded in the year ended December 31, 2019 as a result of a sustained decline in forward commodity benchmark prices for natural gas, natural gas liquids and oil. There was no impairment charge recorded in the corresponding prior period year of 2018.

The following table represents the impact of the impairment charge in each of Bonavista's CGUs due to the sustained decline in the commodity price environment in 2019:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ thousands)				
British Columbia CGU	**14,323**	—	**19,323**	—
Deep Basin CGU	**—**	—	**73,000**	—
West Central CGU	**—**	—	**200,000**	—
Total Impairment	**14,323**	—	**292,323**	—

The recoverable amount of Bonavista's CGUs were estimated based on proved plus probable reserve values using before-tax discount rates specific to the underlying composition of reserve categories and risk profile residing in each CGU. The discount rates applied to the different reserve categories ranged from eight to 15 percent when the value in use methodology was used and ten to 20 percent when the fair value less costs of disposal methodology was used.

For the year ended December 31, 2019, depletion, depreciation and amortization expense, excluding the impact of the impairment charge, decreased nine percent to $207.0 million from $227.4 million for the same period of 2018, due to an eight percent decrease in production volumes on which depletion expense is based. On a per boe basis, depletion, depreciation and amortization expense, excluding the impact of the impairment charge, decreased to $8.95 per boe for the year ended December 31, 2019 from $9.01 per boe for the year ended December 31, 2018.

Decommissioning liability

Bonavista's decommissioning liability results from net ownership interest in oil and natural gas assets including well sites, gathering systems and processing facilities. Bonavista has estimated the net present value of its total decommissioning liability to be $370.6 million at December 31, 2019, compared to an estimated net present value of $430.7 million at December 31, 2018. The estimated decommissioning liability includes management's estimates of abandonment and remediation costs and the time-frame in which the costs are expected to be incurred. An inflation rate and risk-free rate (based on the Bank of Canada's long-term risk-free bond rate) are used to calculate the present value of the decommissioning liability.

During the year of 2019, Bonavista recognized decommissioning liabilities of $1.7 million in connection with its new well development activities and $18.2 million for liabilities acquired. Reflecting the increase in Bonavista's decommissioning liability with the passage of time, accretion expense of $7.4 million was recorded for the year ended December 31, 2019 in net finance costs on the statement of loss and comprehensive loss. During the year ended December 31, 2019, Bonavista's decommissioning liability was reduced by $14.8 million as a result of the disposition of non-core properties and an additional reduction of $9.7 million as a result of Bonavista's active abandonment and reclamation program. Further a $63.0 million decrease to changes of decommissioning liability estimates was recognized largely as a result of changes to liability cost estimates based on specific well attributes and recent results from area-based abandonment programs as well as the recognition of significant abandonment work done at major facilities, partially offset by the revaluation of the acquired liabilities at the long-term risk-free rate. In addition, the change to liability costs estimates include the impact of the decrease in both the discount and inflation rates employed at December 31, 2019. The long-term risk-free rate and inflation rate used to calculate the present value of Bonavista's decommissioning liability at December 31, 2019 were 1.76% and 1.35% respectively, compared to rates of 2.18% and 1.80% used in the present value calculation at December 31, 2018.

Bonavista is committed to operate in a safe, efficient and environmentally responsible manner and is committed to continually improving environmental, health and safety performance. As part of this commitment, Bonavista has an active abandonment and reclamation program that is regularly reviewed by Bonavista's Board of Directors and funded with adjusted funds flow and the bank credit facility. Bonavista's current Liability Management Rating ("LMR") is well within the Alberta Energy Regulator guidelines.

Deferred income tax expense (recovery)

There was no deferred income tax provision recognized for the three months ended December 31, 2019 compared to a deferred income tax provision of $35.3 million recognized in the same period of 2018. For the year ended December 31, 2019, a deferred income tax recovery of $23.0 million was recognized compared to a deferred income tax provision of $15.1 million recognized in the same period of 2018.

On May 28, 2019 the Alberta government tabled legislation to decrease the general corporate tax rate to 11%, from 12% on July 1, 2019, with further one percent rate reductions every year on January 1 until the general corporate tax rate is eight percent on January 1, 2022. As these corporate income tax measures were included in Alberta Bill 3 they were considered substantively enacted under IFRS in the calculation of Bonavista's deferred tax obligations starting in the second quarter of 2019. As a result of the reduction in the corporate provincial tax rate, Bonavista analyzed the expected timing of settlement of the taxable temporary differences which give rise to deferred income tax assets and liabilities and re-measured these amounts using the appropriate, newly enacted corporate provincial income tax rates. This rate reduction resulted in an approximately $10.7 million reduction in Bonavista's deferred income tax asset at December 31, 2019.

As at December 31, 2019, Bonavista unrecognized a deferred tax asset of $73.9 million in respect of deductible temporary differences. The material uncertainty related to the uncertainty of Bonavista's process of negotiating covenant relief, refer to note 2, "Future operations", was considered to affect the assessment of the probability that future taxable income will be available against which the Corporation can utilize the benefits of tax pools in excess of the carrying amount of assets. At December 31, 2019, Bonavista's estimated income tax pools were $2.3 billion. It is expected that future taxable income will be available to utilize the accumulated tax pools. The following table sets forth Bonavista's estimated income tax pools by component for the year ended December 31, 2019 and December 31, 2018.

	December 31, 2019	December 31, 2018
($ thousands)		
Canadian oil and gas property expense	**428,236**	435,744
Canadian development expense	**489,785**	447,826
Canadian exploration expense	**377,419**	369,612
Undepreciated capital cost	**195,817**	218,970
Non-capital losses	**819,307**	818,029
Other	**9,243**	6,954
Total	**2,319,807**	2,297,135

CAPITAL EXPENDITURES

The following table sets forth Bonavista's capital expenditures by category for the three months and year ended December 31:

	Three months ended December 31,			Year ended December 31,		
	2019	2018	% Change	**2019**	2018	% Change
($ thousands)						
Land acquisitions	**322**	6,053	(95)%	**9,392**	8,746	7 %
Geological and geophysical	**850**	1,109	(23)%	**4,158**	6,899	(40)%
Drilling and completion	**5,460**	30,172	(82)%	**92,770**	114,515	(19)%
Production equipment and facilities	**5,334**	7,838	(32)%	**33,230**	34,332	(3)%
Exploration and development expenditures	**11,966**	45,172	(74)%	**139,550**	164,492	(15)%
Property acquisitions	**55,522**	29,211	90 %	**55,395**	32,654	70 %
Property dispositions	**115**	(18,174)	(101)%	**(21,472)**	(26,616)	(19)%
Office equipment	**380**	221	72 %	**1,155**	760	52 %
Net capital expenditures[(1)]	**67,983**	56,430	20 %	**174,628**	171,290	2 %

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. Refer to the section entitled "Non-GAAP Measures".

For the three months ended December 31, 2019, Bonavista's investment in exploration and development activities was $12.0 million, a 74% decrease compared to $45.2 million for the same period of 2018. The decrease in exploration and development expenditures, was due to a significantly reduced development program to accommodate spending on a synergistic asset acquisition in Bonavista's West Central core area closing on December 4, 2019 for cash consideration of $55.6 million. As a result of the asset acquisition and Bonavista's focus on maintaining financial flexibility by funding its capital expenditures through adjusted funds flow, the reduced exploration and development program was primarily focused on completion projects related to third quarter drilling and ongoing support capital projects. In the comparative period of 2018, Bonavista's exploration and development program was predominately focused on natural gas liquids rich development in the West Central and Deep Basin core areas.

For the year ended December 31, 2019, Bonavista's investment in exploration and development activities was $139.6 million, a 15% decrease compared to $164.5 million for the same period of 2018. The decrease in exploration and development expenditures, was primarily due to a reduction in Bonavista's fourth quarter exploration and development program for those reasons noted above. Bonavista remains focused on maintaining a prudent capital spending program that is within adjusted funds flow to support the Corporation's objective of strengthening its financial flexibility.

During the year ended December 31, 2019, total consideration received for non-core assets in the Deep Basin area totaled $21.5 million, resulting in a loss on the sale of property, plant and equipment of $15.3 million and a $1.8 million loss on the sale of exploration and evaluation assets. During the comparative period of 2018, Bonavista disposed of certain non-core properties for total consideration of $26.6 million, resulting in a loss on the sale of property, plant and equipment of $6.7 million and a $0.2 million gain on the sale of exploration and evaluation assets. While there were no material dispositions during the three months ended December 31, 2019, in the comparative period of 2018, the total consideration received for non-core property dispositions was $18.2 million, resulting in a loss on the sale of property, plant and equipment of $12.1 million.

During the year ended December 31, 2019, Bonavista acquired producing properties and petroleum and natural gas rights within its core areas for total consideration of $55.4 million compared to $32.7 million invested in the comparative period of 2018. During the three months ended December 31, 2019, Bonavista acquired producing properties and petroleum and natural gas rights within its core areas for total consideration of $55.5 million compared to $29.2 million invested in the comparative period of 2018. In both years, properties acquired largely integrated in and/or were synergistic with Bonavista's existing assets in its West Central core area.

Office equipment expenditures during the twelve months ended December 31, 2019 and 2018 were $1.2 million and $0.8 million, respectively. Similarly, office equipment expenditures were $0.4 million and $0.2 million respectively for the three months ended December 31, 2019 and 2018. Bonavista's office equipment expenditures in both 2019 and 2018 were largely focused on information technology infrastructure.

CAPITAL RESOURCES AND LIQUIDITY

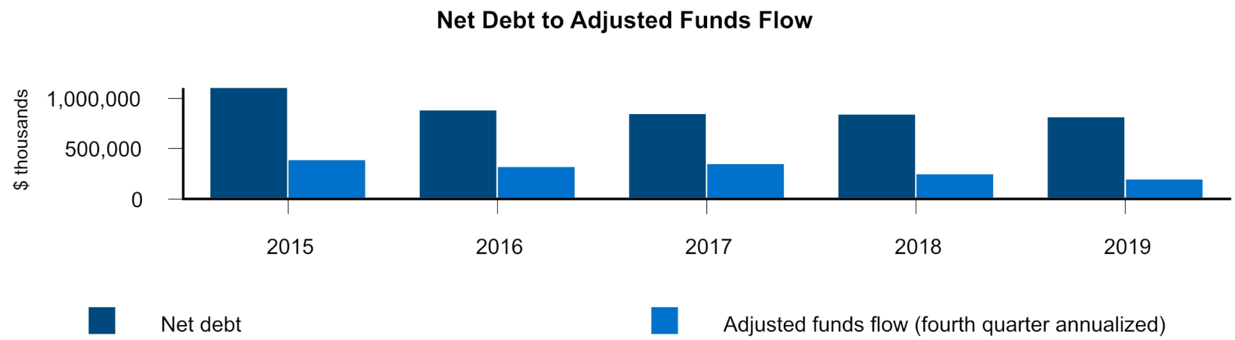
Bonavista has a $500.0 million, covenant-based bank credit facility provided by a syndicate of eight domestic banks. As at December 31, 2019, Bonavista had $53.2 million drawn on its bank credit facility and outstanding letters of credit of $40.0 million, which reduce the available borrowing capacity. At December 31, 2019, Bonavista had $406.8 million of unutilized capacity on its bank credit facility. As at December 31, 2018, Bonavista had $13.0 million drawn on its bank credit facility and outstanding letters of credit of $17.3 million, providing a total unutilized bank borrowing capacity of $469.7 million.

The bank credit facility provides that advances be made by way of Canadian prime rate loans, bankers' acceptances and/or US dollar LIBOR advances. These advances bear interest at the banks' prime rate and/or at money market rates plus a stamping fee. The total stamping fees range between 50 basis points and 215 basis points on Canadian bank prime and US base rate borrowings and between 150 basis points and 315 basis points on Canadian dollar bankers' acceptance and US dollar LIBOR borrowings. The undrawn portion of the bank credit facility is subject to a standby fee in the range of 30 to 63 basis points. For the year ended December 31, 2019 and December 31, 2018, borrowing costs averaged 4.6% and 4.0%, respectively.

Bonavista's senior unsecured notes totaled $753.9 million at December 31, 2019 consisting of US$565.0 million (CDN$733.9 million) and CDN$20.0 million. As at December 31, 2018, Bonavista's senior unsecured notes totaled $790.7 million consisting of US$565.0 million (CDN$770.7 million) and CDN$20.0 million. Bonavista's senior unsecured notes bear fixed interest rates, with a weighted average interest rate of 4.1% and a weighted average life of two-and-a-half years with maturity dates ranging from November 2, 2020 to May 23, 2025.

Although, the underlying value of Bonavista's senior unsecured notes did not change between December 31, 2019 and December 31, 2018, its overall indebtedness decreased as a result of the revaluation of its US denominated senior unsecured notes at the end of the reporting period. This revaluation resulted in an unrealized foreign exchange gain of $36.8 million for the year ended December 31, 2019. The unrealized gain was due to the strengthening of the CDN dollar relative to the US dollar, which at December 31, 2019 was $1.2990 CDN$/US$ compared to the December 31, 2018 rate of $1.3641 CDN$/US$.

At December 31, 2019, Bonavista's net debt was $808.6 million with net debt to fourth quarter of 2019 annualized adjusted funds flow ratio of 4.2:1. In comparison to December 31, 2018, Bonavista's net debt was $835.9 million with net debt to fourth quarter of 2018 annualized adjusted funds flow ratio of 3.4:1. This ratio represents the time period it would take to pay off Bonavista's net debt if no further capital expenditures were incurred and if adjusted funds flow remained constant. This ratio may increase at certain times as a result of acquisitions, low commodity prices and foreign exchange fluctuations.



The following table provides a reconciliation of long-term debt to net debt and the net debt to adjusted funds flow ratio:

	December 31, 2019	December 31, 2018
($ thousands)		
Long-term debt	**598,031**	801,625
Working capital(1)(4)	**223,352**	(8,545)
Current assets		
Financial instrument commodity contracts	**39,508**	57,192
Current liabilities		
Financial instrument commodity contracts	**(40,568)**	(2,663)
Lease liabilities(3)	**(3,085)**	—
Decommissioning liabilities	**(8,650)**	(11,704)
Net debt(2)	**808,588**	835,905
Adjusted funds flow (fourth quarter annualized)(2)	**190,808**	244,300
Net debt to adjusted funds flow ratio (fourth quarter annualized)(2)	**4.2:1**	3.4:1
Adjusted funds flow(2)	**180,972**	259,595
Net debt to adjusted funds flow (ratio)(2)	**4.5:1**	3.2:1

Notes:

(1) Working capital is equal to current assets less current liabilities as presented on the consolidated statement of financial position. Current assets as at December 31, 2019 were $113.3 million compared to current liabilities of $336.7 million. Current assets as at December 31, 2018 were $127.1 million compared to current liabilities of $118.6 million.

(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) Lease liabilities are included in "accounts payable and accrued liabilities" on the consolidated statement of financial position.

(4) Working capital deficiency as at December 31, 2019 includes $207.7 million of the current portion of long-term debt. There was no long-term debt classified as current in the comparative 2018 period.

As at December 31, 2019, Bonavista had $207.7 million of senior unsecured notes due within the next twelve months which it expects to pay through a combination of adjusted funds flow and its bank credit facility. This expectation may change as a result of Bonavista's ongoing covenant relief process, refer to note 2, "Future operations".

Bonavista's capital plan for 2020 will be to spend within adjusted funds flow, targeting an exploration and development program of between $100 and $120 million, the majority of which will be allocated to the West Central core area. Spending levels have been designed to maintain production levels consistent with 2019 at between 62,000 and 65,000 boe per day.

Debt covenants

Under the terms of the bank credit facility and senior unsecured notes, Bonavista has provided the covenants that its:

- consolidated senior debt borrowing will not exceed three and one-half times net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment;
- consolidated total debt will not exceed three and one-half times net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment; and
- consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated shareholders' equity of the Corporation, in all cases calculated based on a rolling prior four quarters.

Further under the terms of the covenants consolidated net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment, as applicable with any acquisition or disposition (the net proceeds of which are greater than $20 million or the Canadian Dollar Exchange Equivalent thereof) made within the applicable period, is to be adjusted as if the acquisition or disposition had been made at the beginning of such period. Furthermore, financial letters of credit are to be included in the determination of consolidated total debt and consolidated senior debt whereas non-financial letters of credit are excluded from such calculations.

Bonavista's consolidated senior debt and consolidated total debt were the same at December 31, 2019 and include Bonavista's senior unsecured notes issued under the master shelf agreement, senior unsecured notes not subject to the master shelf agreement and the bank credit facility. Bonavista's consolidated senior debt may differ from total debt in instances when the Corporation issues senior subordinated debt or enters into a significant capital lease obligation or guarantee. In accordance with the terms of Bonavista's bank credit facility the calculation of senior debt and total debt remained unchanged with the adoption of IFRS 16 *Leases.*

As at December 31, 2019, Bonavista was in compliance with all covenants under its credit facilities and senior unsecured notes. Total long-term debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment ("EBITDA") and total senior debt to EBITDA was 3.32 times compared to the covenant of less than 3.5 times and total long-term debt to capitalization was 0.41 times compared to the covenant of less than 0.5 times. The ratio of total senior debt to EBITDA, total debt to EBITDA and total long-term debt to capitalization are susceptible to factors that impact earnings, the most significant of which are changes in commodity prices. Bonavista does anticipate a breach in covenants within the first six months of 2020, refer to note 2, "Future operations."

OUTSTANDING SHARE INFORMATION

Shareholders' equity

As at December 31, 2019, Bonavista had 265.2 million equivalent common shares outstanding. This includes 3.1 million exchangeable shares, which are exchangeable into 4.7 million common shares. The exchange ratio in effect at December 31, 2019 for exchangeable shares was 1.51204:1. As at December 31, 2019, Bonavista had 3.9 million restricted incentive awards and 6.4 million performance incentive awards outstanding under its long-term incentive plans. The number of common shares available for issue under the restricted incentive award plan and the performance incentive award plan is limited to 5.4% of Bonavista's issued and outstanding common shares including common shares issuable on the exchange of outstanding exchangeable shares, as approved by shareholders. As at December 31, 2019, the number of shares issuable under Bonavista's long-term incentive plans, in aggregate represented 3.9% of the issued and outstanding common shares including common shares issuable on the conversion of outstanding exchangeable shares.

The following table provides a reconciliation of Bonavista's common shares and exchangeable shares outstanding:

	Common Shares	**Exchangeable Shares**
	(thousands)	(thousands)
Balance as at December 31, 2017	251,747	3,238
Issued on conversion of exchangeable shares	196	(133)
Conversion of restricted incentive and performance incentive awards	3,510	—
Balance as at December 31, 2018	255,453	3,105
Issued on conversion of exchangeable shares	**24**	**(16)**
Conversion of restricted and performance incentive awards	**5,085**	**—**
Balance as at December 31, 2019	**260,562**	**3,089**

As at February 13, 2020, Bonavista had 265.2 million equivalent common shares outstanding. This includes 3.1 million exchangeable shares, which are exchangeable into 4.7 million common shares. The exchange ratio in effect on February 13, 2020 for exchangeable shares was 1.51204:1. In addition as of February 13, 2020, Bonavista had 4.1 million restricted incentive awards and 6.4 million performance incentive awards outstanding under its long-term incentive plans. As at February 13, 2020, the number of shares issuable under Bonavista's long-term incentive plans, in aggregate represented 4.0% of the issued and outstanding common shares including common shares issuable on the conversion of outstanding exchangeable shares.

Dividends

Dividends declared during the year ended December 31, 2019 were $0.01 per share compared to $0.04 per share for the year ended December 31, 2018. Dividends approved by the Board of Directors are dependent upon the commodity price environment, production levels and the amount of capital expenditures to be financed from adjusted funds flow. On May 2, 2019, Bonavista's Board of Directors suspended the quarterly dividend.

Lease obligations

The following table is a summary of Bonavista's lease liabilities associated with its Calgary head office, field equipment and certain vehicle obligations. Prior the adoption of IFRS 16 *Leases* on January 1, 2019 these leases would have been treated as operating leases whereby the lease payments were included in operating expenses or general and administrative expenses depending on the nature of the lease.

($ thousands)	
Balance as at January 1, 2019	**8,926**
Interest expense	**279**
Lease payments	**(5,178)**
Balance as at December 31, 2019	**4,027**
Current portion of lease liabilities[1]	3,085
Long-term portion of lease liabilities[2]	942

Notes:

(1) Recorded in "accounts payable and accrued liabilities" on the consolidated statement of financial position.
(2) Recorded in "other long-term liabilities" on the consolidated statement of financial position.

On July 25, 2019, Bonavista entered into a new four-and-a-half year lease for its Calgary head office space commencing on August 1, 2020. The estimated right-of-use asset and lease liability that will be recognized when Bonavista assumes possession of the new office space is $4.8 million.

Contractual obligations and commitments

Bonavista enters into various contractual obligations and commitments in the normal course of operations. The following table provides a summary of Bonavista's contractual obligations and commitments at December 31, 2019:

($ thousands)	Total	2020	2021	2022	2023	2024 and thereafter
Long-term debt repayments[1][3][4]	805,767	207,736	247,201	64,858	130,202	155,770
Interest payments[2][3]	78,768	29,578	20,489	13,068	7,844	7,789
Transportation expenses[5]	135,547	31,709	27,889	25,261	9,511	41,177
Total contractual obligations	**1,020,082**	**269,023**	**295,579**	**103,187**	**147,557**	**204,736**

Notes:

(1) Long-term debt repayments include the principal payments due on senior unsecured notes. Based on the existing terms of the revolving bank credit facility, the amounts owing under this facility are required to be paid on September 10, 2021.
(2) Fixed interest payments on senior unsecured notes.
(3) US dollar payments are converted using the exchange rate at December 31, 2019 of $1.2990 CDN to $1.0000 US dollar.
(4) With respect to the long-term debt repayment obligations Bonavista has entered into financial instrument contracts to reduce its exposure to the CDN dollar to the US dollar exchange rate associated with the future cash repayments of its US denominated senior unsecured notes. The underlying notional amount of the financial instrument contracts maturing on the maturity dates of Bonavista US denominated senior unsecured notes is US$23.3 million at an average CDN$/US$ rate of $1.3302.
(5) Includes a Long Term Fixed Price (LTFP) contract with TransCanada that commenced November 1, 2017. This 10-year contract contains an early termination policy after 5 years which has been assumed to be exercised in the contractual obligation above.

SELECTED ANNUAL INFORMATION

For the years ended December 31	2019	2018	2017
($ thousands, except per boe and per share)			
Production revenues	**372,405**	514,967	553,002
Production:			
Natural gas (mmcf/day)	**266**	297	306
Natural gas liquids (bbls/day)	**17,162**	17,366	18,794
Oil (bbls/day)(1)	**1,804**	2,221	2,415
Total oil equivalent (boe/day)	**63,357**	69,154	72,156
Product prices:(2)			
Natural gas ($/mcf)	**2.32**	2.78	3.05
Natural gas liquids ($/bbl)	**24.97**	29.30	27.29
Oil ($/bbl)(1)	**61.47**	53.07	57.80
Total oil equivalent ($/boe)	**18.26**	21.04	21.97
Net income (loss)	**(389,997)**	11,815	(27,930)
Per share(3)	**(1.48)**	0.05	(0.11)
Cash flow from operating activities	**195,736**	291,191	325,619
Per share(3)	**0.74**	1.13	1.27
Adjusted funds flow(4)	**180,972**	259,595	301,988
Per share(3)	**0.69**	1.00	1.18
Operating netback ($/boe)(4)	**10.35**	12.64	13.85
Cash costs ($/boe)(4)	**9.56**	9.39	8.92
Operating expenses ($/boe)	**5.76**	5.70	5.59
General and administrative expenses ($/boe)	**0.89**	0.96	0.94
Net capital expenditures(4)	**174,628**	171,290	281,745
Total assets	**2,495,297**	2,923,709	2,959,470
Shareholders' equity	**1,169,757**	1,552,184	1,539,461
Long-term debt(5)	**805,767**	801,625	800,544
Net debt(4)	**808,588**	835,905	840,173
Weighted average outstanding equivalent shares: (thousands)(3)			
Basic	**263,147**	258,781	255,559
Diluted	**272,619**	265,671	262,046
Dividends declared	**2,558**	10,168	10,040
Per share	**0.01**	0.04	0.04

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) Basic per share calculations include exchangeable shares which are convertible into common shares on certain terms and conditions.
(4) 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".
(5) Long-term debt includes $207.7 million of the current portion of long-term year ended December 31, 2019. There was no long-term debt classified as current in the comparative 2018 period.

SUMMARY OF HISTORICAL QUARTERLY RESULTS

The following table provides a summary of Bonavista's quarterly results for the eight most recently completed quarters:

	2019				2018			
Quarter ending	**Dec 31**	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Financial								
($ thousands, except per boe and per share amounts)								
Production revenues	**100,742**	69,542	81,485	120,636	124,302	131,175	121,102	138,388
Net income (loss)	**(44,201)**	(307,489)	1,828	(40,135)	81,227	(17,811)	(49,564)	(2,037)
Per share(1)	**(0.17)**	(1.16)	0.01	(0.15)	0.31	(0.07)	(0.19)	(0.01)
Cash flow from operating activities	**47,952**	37,113	56,186	54,485	77,581	73,720	63,842	76,048
Per share(1)	**0.18**	0.14	0.21	0.21	0.30	0.28	0.25	0.30
Adjusted funds flow(2)	**47,702**	34,565	40,524	58,181	61,075	63,688	65,704	69,128
Per share(1)	**0.18**	0.13	0.15	0.22	0.23	0.25	0.25	0.27
Dividends declared	**—**	—	—	2,558	2,555	2,554	2,536	2,523
Per share(1)	**—**	—	—	0.01	0.01	0.01	0.01	0.01
Total assets	**2,495,297**	2,547,412	2,896,501	2,867,965	2,923,709	2,845,288	2,889,457	2,933,854
Shareholders' equity	**1,169,757**	1,212,177	1,518,210	1,512,870	1,552,184	1,471,682	1,490,460	1,539,073
Long-term debt(3)	**805,767**	766,569	763,376	781,168	801,625	760,231	809,099	802,394
Net debt(2)	**808,588**	801,921	795,987	811,440	835,905	795,023	826,552	839,619
Capital expenditures:								
Exploration and development	**11,966**	43,284	35,277	49,023	45,172	42,317	33,148	43,855
Acquisitions, net of dispositions(4)	**55,637**	(16,299)	(37)	(5,378)	11,037	(5,821)	725	97
Corporate	**380**	347	309	119	221	57	337	145
Weighted average outstanding equivalent shares: (thousands)(1)								
Basic	**265,195**	264,991	261,923	260,305	260,047	259,897	258,002	257,030
Diluted	**275,492**	275,435	275,628	272,236	267,135	266,913	266,999	267,120
Operating								
(boe conversion – 6:1 basis)								
Production:								
Natural gas (mmcf/day)	**260**	260	264	282	281	287	301	322
Natural gas liquids (bbls/day)	**18,003**	17,310	15,387	17,945	19,131	17,868	15,950	16,480
Oil (bbls/day)(5)	**1,587**	1,813	1,830	1,988	2,108	2,358	2,091	2,327
Total oil equivalent (boe/day)	**62,923**	62,437	61,186	66,937	68,011	68,036	68,214	72,417
Product prices:(6)								
Natural gas ($/mcf)	**2.39**	2.02	2.24	2.61	2.91	2.76	2.62	2.85
Natural gas liquids ($/bbl)	**27.34**	19.98	23.22	28.95	24.99	28.90	32.56	31.68
Oil ($/bbl)(5)	**60.51**	63.24	61.93	60.21	28.47	58.84	64.15	59.81
Total oil equivalent ($/boe)	**19.23**	15.78	17.36	20.54	19.91	21.27	21.16	21.79
Operating expenses ($/boe)	**5.76**	5.59	5.86	5.85	5.66	5.74	5.78	5.64
Transportation expenses ($/boe)	**1.37**	1.38	1.43	1.44	1.37	1.42	1.32	1.23
General and administrative expenses ($/boe)	**0.86**	0.90	0.96	0.84	0.87	0.92	0.96	1.09
Cash costs ($/boe)(2)	**9.55**	9.42	9.78	9.55	9.27	9.46	9.47	9.38
Operating netback ($/boe)(2)	**11.04**	8.49	9.82	11.92	11.99	12.48	12.95	13.11
Trading Statistics								
($ per share, except volume)								
High	**0.63**	0.86	1.20	1.39	1.60	1.63	1.75	2.32
Low	**0.45**	0.41	0.46	1.06	1.01	1.25	1.13	1.11
Close	**0.61**	0.61	0.49	1.11	1.20	1.49	1.49	1.18
Average Daily Volume - Shares	**261,785**	462,855	589,117	531,298	817,647	527,770	1,086,460	1,070,659

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) Includes the current portion of long-term debt.
(4) Expenditures on property acquisitions, net of property dispositions.
(5) Oil includes light, medium and immaterial amounts of heavy oil.
(6) Product prices include realized gains and losses on financial instrument commodity contracts.

Production revenues over the past eight quarters have fluctuated largely due to the volatility of commodity prices and changes in production volumes. Net income (loss) in the past eight quarters has fluctuated from a net loss of $307.5 million in the third quarter of 2019 to net income of $81.2 million in the fourth quarter of 2018. These fluctuations are primarily influenced by commodity prices, realized and unrealized gains and losses on financial instrument contracts, unrealized gains and losses on the revaluation of Bonavista's US dollar denominated senior unsecured notes, gains and losses on the acquisition and disposition of property, plant and equipment, gains and losses on the disposition of exploration and evaluation assets and impairment charges.

CONTROLS AND PROCEDURES

Disclosure controls and procedures

The Corporation's Chief Executive Officer and Chief Financial Officer (the "Certifying Officers") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 - *Certification of Disclosure in Issuer's Annual and Interim Filings* ("NI 52-109"), to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the Certifying Officers by others, particularly during the period in which the annual and interim filings or other reports filed or submitted by the Corporation under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Certifying Officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's DC&P at December 31, 2019 and have concluded that the Corporation's DC&P were effective at December 31, 2019.

Internal control over financial reporting

The Corporation’s Certifying Officers have designed, or caused to be designed under their supervision, internal controls over financial reporting ("ICFR"), as defined by National Instrument 52-109, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the generally accepted accounting principles applicable to the Corporation. The control framework the Certifying Officer used to design the Corporation's ICFR is "Internal Control - Integrated Framework (2013)" published by The Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Certifying Officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Corporation's ICFR at December 31, 2019 and have concluded that the Corporation's ICFR was effective at December 31, 2019. There were no changes in the Corporation's ICFR that occurred during the period beginning on October 1, 2019 and ended on December 31, 2019 that have materially affected, or are reasonably likely to materially affect, the Corporation's ICFR.

While the Certifying Officers believe that the Corporation's ICFR provides a reasonable level of assurance and is effective, they do not expect that the ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenue and expenses during the period. Estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as Bonavista's operating environment changes.

Estimates and underlying assumptions are reviewed on an ongoing basis by management. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The key sources of estimation uncertainty to the carrying amounts of assets and liabilities are discussed below:

i. Determination of a Cash-Generating Unit (“CGU”)

   The determination of Bonavista’s CGUs is subject to management’s judgment. In determining Bonavista’s CGUs, management assessed what constituted independent cash flows and how to aggregate the respective assets. The asset composition of each CGU can directly impact the assessment of the recoverability of those assets included within each CGU. Bonavista's current CGU composition includes its British Columbia CGU, Deep Basin CGU and West Central CGU.

ii. Impairment testing

   Bonavista assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, Bonavista performs an impairment test on the CGU, which is the lowest level at which there are identifiable cash flows. The carrying amount of each CGU is compared to its recoverable amount which is defined as the greater of its fair value less costs of disposal and value in use and is subject to management estimates. Bonavista also assesses its property, plant and equipment to determine if events or circumstances would support the reversal of any previously recorded impairment charges. In this assessment Bonavista considers the facts and circumstances that caused the original impairment charge to be recognized and whether there is a sustained period in which those facts and circumstances changed.

At December 31, 2019, Bonavista evaluated each of its CGUs for indicators of potential impairment or a reversal of previously recorded impairment charges. Key estimates used in the determination of cash flows used to calculate the recoverable amount of a CGU include: quantities of reserves and future production; future commodity pricing; development costs; operating costs; royalty obligations; and discount rates. Any changes in these estimates may have an impact on the recoverable amount of the CGU. Bonavista identified indicators of impairment at December 31, 2019 as a result of a sustained decline in forward commodity benchmark prices for natural gas, natural gas liquids and oil. As such impairment tests were conducted on each of Bonavista's CGUs at December 31, 2019, refer to note 12, "Property, Plant and Equipment". Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal.

iii. Proved plus probable oil and natural gas reserves

Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to interpretation and uncertainty. Bonavista expects that over time its reserve estimates will be revised either upward or downward depending upon the factors as stated above. These reserve estimates can have a significant impact on net income (loss), as it is a key component in the calculation of depletion, depreciation and amortization, and also for the determination of potential asset impairments or reversals.

iv. Depreciation, depletion, amortization and impairment

Property, plant and equipment is measured at cost less accumulated depreciation, depletion, amortization and impairment. Bonavista's oil and natural gas properties are depleted using the unit-of-production method over proved plus probable reserves for each CGU. The unit-of-production method takes into account estimates of capital expenditures incurred to date along with future development capital required to develop both proved and probable reserves.

iv. Decommissioning liability

The provision for decommissioning liabilities is based on management's estimates of costs and planned remediation projects. Actual costs may differ from those estimated due to changes in governing environment laws and regulations, technological changes, and market conditions. The estimate for decommissioning liabilities is also impacted by the rates used to estimate the present value of the decommissioning liability. The estimate for decommissioning liabilities is also impacted by the risk-free and inflation rates used to estimate the present value of the decommissioning liability, refer to note 16, "Decommissioning liabilities".

iv. Financial instrument contracts

The estimated fair value of financial instrument commodity contracts are subject to changes in forward looking commodity prices, interest rate curves, volatility curves and counterparty non-performance risk. The estimated fair values of the Corporation's financial instrument contracts are subject to changes in foreign exchange rates.

CHANGES IN ACCOUNTING POLICIES

- **Adoption of IFRS 16, "Leases"**

Effective January 1, 2019, Bonavista adopted IFRS 16 *Leases* ("IFRS 16"), which replaced IAS 17 *Leases.* The Corporation has applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. On adoption, the Corporation elected to use the following practical expedients permitted under the standard:

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of low dollar value (less than US$5 thousand); and
- The use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease.

The cumulative effect of initially applying the standard was recognized as a $6.4 million increase to right-of-use assets (included in "property, plant and equipment") and an increase of $8.9 million to lease obligations (included in "accounts payable and accrued liabilities" and "other long-term liabilities"). The right-of-use assets recognized were measured at amounts equal to the present value of the lease obligations less lease incentives received. The weighted average incremental borrowing rate used to determine the lease obligations at adoption was approximately 4.3%. The right-of-use assets and lease obligations recognized relate to the Corporation's head office lease in Calgary, field equipment and certain vehicles.

The financial statement impact of IFRS 16 is subject to certain management judgments and estimates. Specifically, extension and termination provisions are included in certain lease contracts. In determining the lease term to be recognized, management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. In addition, the measurement of lease obligations is subject to management's judgment in the determination of the applicable incremental borrowing rate.

- **Adoption of Deferred Share Unit Plan**

  In 2019, Bonavista adopted a deferred share unit ("DSU") plan primarily for non-management directors and non-executive officers which entitles participants to receive cash, based on the trading price of the Corporation's common shares on the payment date. Deferred share units can only be redeemed following the participants departure from the Corporation and must be redeemed prior to December 1st of the year following the departure date. A liability for the expected cash payments is accrued over the life of the deferred share unit based on the closing price of the Corporation's common shares. Compensation expense is recorded in "share-based compensation" on the Corporation's consolidated statement of income (loss) and comprehensive income (loss).

- **Adoption of amendments to IFRS 3, "Business Combinations"**

  On October 22, 2018, the IASB issued amendments to the guidance in IFRS 3 *Business Combinations* ("IFRS 3"), revising the definition of a business and providing for the addition of an optional 'concentration test' to determine if the acquisition is a business. To be considered a business under the amendments to IFRS 3, an acquisition would have to include an input and a substantive process that together significantly contribute to the ability to create outputs. The three elements of a business are defined as follows:

  - Input - Any economic resource that creates outputs, or has the ability to contribute to the creation of outputs, when one or more processes are applied to it.
  - Process - Any system, standard, protocol, convention or rule that, when applied to an input or inputs, creates outputs or has the ability to contribute to the creation of outputs.
  - Output - The result of inputs and processes applied to those inputs that provide goods or services to customers, generate investment income or generate other income from ordinary activities.

  The optional 'concentration test' permits a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. An entity may elect to apply, or not apply, the test. An entity may make such an election separately for each transaction or other event. If the concentration test is met, the sets of activities and assets is determined not to be a business and no further assessment is needed.

  The amendments to IFRS 3 apply to businesses acquired in annual reporting periods beginning on or after January 1, 2020, with early adoption permitted. Bonavista has chosen to early adopt the amendments to IFRS 3 effective January 1, 2019.

RISK FACTORS AND RISK MANAGEMENT

The following are the primary risks associated with the business of Bonavista. Most of these risks are similar to those affecting others in the conventional oil and natural gas sector. Bonavista's financial position and results of operations are directly impacted by these factors:

- Operational risks associated with the exploration, development and production of oil and natural gas;
- Commodity risk as crude oil, condensate and natural gas prices and differentials fluctuate due to market forces;
- Market risk relating to global supply and demand for oil and natural gas and market prices for oil and natural gas;
- Market risk relating to Bonavista's ability to acquire capacity on pipelines to deliver natural gas to commercial markets;
- Political uncertainty in Canada and the impact on liquefied natural gas and other infrastructure projects;
- Operational risk associated with third party facility outages and downtime;
- Reserves risk with respect to the quantity and quality of recoverable reserves;
- Financial risk such as volatility of the CDN$/US$ dollar exchange rate, interest rates and debt service obligations;
- Financial risk relating to change in investor sentiment towards oil and natural gas operations;
- Risk that Bonavista's lenders will not provide covenant relief and Bonavista's credit facility and senior unsecured notes will become due on demand;
- Risk associated with the re-negotiation of Bonavista's credit facility and the continued participation of Bonavista's lenders;
- Risk associated with the negotiation of covenant relief from Bonavista's senior noteholders;
- Environmental and safety risk associated with well operations and production facilities;
- Changing government regulations relating to royalty legislation, income tax laws, incentive programs, operating practices, fracturing regulations and environmental protection relating to the oil and natural gas industry; and
- Labour risk related to availability, productivity and retention of qualified personnel.

Bonavista seeks to mitigate these risks by:

- Acquiring properties with established production trends to reduce technical uncertainty as well as undeveloped land with development potential;
- Maintaining a low-cost structure to maximize product netbacks and reduce impact of commodity price volatility;
- Diversifying properties to mitigate individual property and well risk;
- Maintaining a risk management program that allows for Bonavista to enter into a financial instrument commodity contract to reduce Bonavista's exposure to commodity price volatility;
- Adhering to Bonavista's safety program and keeping abreast of current operating best practices;
- Keeping informed of proposed changes in regulations and laws to properly respond to and plan for the effects that these changes may have on our operations;
- Establishing and maintaining adequate cash resources to fund future abandonment and site restoration costs;
- Increasing transparency over social, environment and governance policies and practices through corporate responsibility reporting;
- Closely monitoring performance against financial covenants and preparing forecasts;
- Closely monitoring commodity prices and capital programs to manage financial leverage; and
- Monitoring the debt and equity markets to understand how changes in the capital markets may impact Bonavista's business plan.

While the foregoing list notes the primary business risks to Bonavista, it is not exhaustive. For additional information on Bonavista's business risks and how Bonavista seeks to mitigate them reference should be made to the "Risk Factors" section in 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.

ABBREVIATIONS

AECO	benchmark price for natural gas determined at the AECO 'C' hub in southeast Alberta
AER	Alberta Energy Regulator
bcf	billion cubic feet
bbl	barrel
bbls	barrels
bbls per day	barrels per day
boe	barrel(s) of oil equivalent
boe per day	barrels of oil equivalent per day
Chicago	Chicago city-gate benchmark price for natural gas
CNWY PN	Conway propane benchmark price
CO_2e	Carbon dioxide equivalent
DAWN	natural gas traded at Union Gas Dawn hub in Dawn Township, Ontario
FID	final investment decision
GAAP	generally accepted accounting principles
GHG	greenhouse gas
GJ	gigajoule
IFRS	International Financial Reporting Standards
LNG	Liquefied natural gas
LTFP	Long term fixed price contract
NGLs	natural gas liquids
NGTL	NOVA Gas Transmission Ltd.
NYMEX	New York Mercantile Exchange natural gas futures benchmark price
mcf	thousand cubic feet
mcf per day	thousand cubic feet per day
Mcfe	Mcf of natural gas equivalent
mtonnes	thousands tonnes
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrel(s) of oil equivalent
mmboe	million barrel(s) of oil equivalent
mmcf	million cubic feet
mmcf per day	million cubic feet per day
MMbtu	million British Thermal Units
MSW	benchmark price for mixed sweet crude determined at Edmonton, Alberta
MTB BT	Mont Belvieu 65 nC4/35 iC4 benchmark price
sections	an area of land containing 640 acres
tcf	trillion cubic feet
tonnes	unit of mass equal to 1,000 kilograms
Ventura	natural gas traded at Ventura in Hancock County, Iowa
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate

NON-GAAP MEASURES

The Corporation uses terms that are commonly used in the oil and natural gas industry, but do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other entities. Management believes that the presentation of these non-GAAP measures provides 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.

On January 1, 2019, Bonavista adopted IFRS 16, *Leases* using the modified retrospective approach and as such prior period comparatives were not restated. As a result of the adoption of IFRS 16, Bonavista's definition of net debt was updated to specifically exclude lease liabilities from the definition which is consistent with the treatment under the Corporation's bank credit facility and senior unsecured notes.

The following list identifies the non-GAAP measures included in Bonavista's MD&A, a description of how the measure has been calculated by Bonavista, a discussion of why Bonavista's management has deemed the measure to be useful and a reconciliation to the most comparable GAAP measure.

- **Adjusted funds flow**

  Adjusted funds flow is based on cash flow from operating activities, excluding changes in non-cash working capital, decommissioning expenditures and including interest expense. Adjusted funds flow per share is calculated by dividing adjusted funds flow by total outstanding common shares together with common shares issuable upon the exchange of outstanding exchangeable shares.

  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).

  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. Reference should be made to note 8, "Capital Management" of the consolidated financial statements.

  The following table provides a reconciliation between the non-GAAP measure of adjusted funds flow to the most directly comparable GAAP measure of cash flow from operating activities:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ thousands)				
Cash flow from operating activities	**47,952**	77,581	**195,736**	291,191
Interest expense[(1)]	**(9,011)**	(8,553)	**(34,938)**	(35,141)
Decommissioning expenditures[(2)]	**2,610**	2,198	**9,743**	12,318
Changes in non-cash working capital[(3)]	**6,151**	(10,151)	**10,431**	(8,773)
Adjusted funds flow	**47,702**	61,075	**180,972**	259,595

Notes:

(1) Interest expense on Bonavista's long-term debt excluding the amortization of debt issuance costs.

(2) The timing of when decommissioning expenditures are incurred is predominately at the discretion of Bonavista's management. However, there is a non-discretionary component that relates to compliance with regulatory requirements and abandonment and reclamation projects where Bonavista is not the operator. For the three months ended December 31, 2019 the non-discretionary component of Bonavista's decommissioning expenditures was $0.9 million (December 31, 2018 - $0.6 million). For the year ended December 31, 2019 the non-discretionary component of Bonavista's decommissioning expenditures was $2.2 million (December 31, 2018 - $3.6 million).

(3) Refer to note 10, "Supplemental cash flow information" in the consolidated financial statements.

- **Operating netback**

  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.

The following table provides a reconciliation between the non-GAAP measure of operating netback to the most directly comparable GAAP measure of net income (loss) for the three months and year ended December 31:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ thousands, except for per boe amounts)				
Net income (loss)	**(44,201)**	81,227	**(389,997)**	11,815
Adjustments for:				
Unrealized losses (gains) on financial instrument commodity contracts	**35,293**	(139,841)	**82,106**	(43,014)
General and administrative expenses	**4,961**	5,413	**20,577**	24,291
Share-based compensation expense	**1,680**	1,732	**9,961**	10,381
Loss on disposition of property, plant and equipment	**222**	12,057	**15,337**	6,725
Loss (gain) on disposition of exploration and evaluation assets	**—**	9	**1,772**	(167)
Depletion, depreciation, amortization and impairment	**62,374**	56,177	**499,290**	227,447
Net finance costs	**3,611**	22,958	**23,131**	66,450
Deferred income tax provision (recovery)	**—**	35,309	**(23,011)**	15,099
Operating netback	**63,940**	75,041	**239,166**	319,027
Operating netback per boe	**11.04**	11.99	**10.35**	12.64

For additional reference the following table provides a compilation of the line items from Bonavista's consolidated statement of income (loss) that comprise operating netback on a per boe basis for the three months and year ended December 31:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ per boe)				
Production revenues	**17.40**	19.87	**16.10**	20.40
Realized gains on financial instrument commodity contracts	**1.83**	0.04	**2.16**	0.64
Production revenues and realized gains on financial instrument commodity contracts	**19.23**	19.91	**18.26**	21.04
Royalties	**1.06**	0.89	**0.75**	1.36
Operating expenses	**5.76**	5.66	**5.76**	5.70
Transportation expenses	**1.37**	1.37	**1.40**	1.34
Operating netback	**11.04**	11.99	**10.35**	12.64

- **Operating margin**

Operating margin is equal to production revenues and realized gains and losses on financial instrument commodity contracts less royalties, operating expenses and transportation expenses; divided by production revenues and realized gains and losses on financial instrument commodity contracts. Realized gains and losses on financial instrument commodity contracts represent the portion of Bonavista's financial instrument commodity contracts that have settled in cash during the period and disclosing this impact provides transparency on how Bonavista's risk management program impacts the operating netback and operating margin metrics. Operating margin is calculated using per boe amounts.

Operating margin is used by management to show operating performance at both a disaggregated (core area) and aggregated level (corporate). This metric is used by management to illustrate the proportion of Bonavista's revenue available for expenditures after operating expenditures are considered.

The following table sets forth the details of the calculation of the operating margin ratio for the three months and year ended December 31:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ per boe)				
Production revenues	**17.40**	19.87	**16.10**	20.40
Realized gains on financial instrument commodity contracts	**1.83**	0.04	**2.16**	0.64
Production revenues and realized gains on financial instrument commodity contracts	**19.23**	19.91	**18.26**	21.04
Royalties	**1.06**	0.89	**0.75**	1.36
Operating expenses	**5.76**	5.66	**5.76**	5.70
Transportation expenses	**1.37**	1.37	**1.40**	1.34
Operating netback	**11.04**	11.99	**10.35**	12.64
Operating margin[1]	**57%**	60%	**57%**	60%

Note:

(1) Ratio of operating netback to production revenues and realized gains on financial instrument commodity contracts.

- **Cash costs**

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.

The following table provides a reconciliation between the non-GAAP measure of cash costs to the most directly comparable GAAP measure of net income (loss) for the three months and year ended December 31:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ thousands, except for per boe amounts)				
Net income (loss)	**(44,201)**	81,227	**(389,997)**	11,815
Adjustments for:				
Production revenues, net of royalties and financial instrument commodity contracts	**(69,909)**	(258,867)	**(322,862)**	(539,704)
Share-based compensation expense	**1,680**	1,732	**9,961**	10,381
Loss on disposition of property, plant and equipment	**222**	12,057	**15,337**	6,725
Loss (gain) on disposition of exploration and evaluation assets	**—**	9	**1,772**	(167)
Depletion, depreciation, amortization and impairment	**62,374**	56,177	**499,290**	227,447
Net finance costs (income) excluding interest expense	**(5,400)**	14,405	**(11,807)**	31,309
Deferred income tax expense (recovery)	**—**	35,309	**(23,011)**	15,099
Cash costs	**(55,234)**	(57,951)	**(221,317)**	(237,095)
Cash costs per boe	**(9.55)**	(9.27)	**(9.56)**	(9.39)

For additional reference the following table provides a compilation of the line items from Bonavista's consolidated statement of income (loss) that comprise cash costs on a per boe basis for the three months and year ended December 31:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ per boe)				
Operating expenses	**5.76**	5.66	**5.76**	5.70
Transportation expenses	**1.37**	1.37	**1.40**	1.34
General and administrative expenses	**0.86**	0.87	**0.89**	0.96
Interest expense	**1.56**	1.37	**1.51**	1.39
Cash costs	**9.55**	9.27	**9.56**	9.39

- **Net capital expenditures**

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.

The following table provides a reconciliation between the non-GAAP measure of net capital expenditures to the most directly comparable GAAP measure of cash flow used in investing activities for the three months and year ended December 31:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ thousands)				
Cash flow used in investing activities	**(89,045)**	(59,972)	**(196,068)**	(188,094)
Changes in non-cash working capital	**21,062**	3,542	**21,440**	16,804
Net capital expenditures	**(67,983)**	(56,430)	**(174,628)**	(171,290)

- **Net debt**

Bonavista has calculated net debt based on the 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.

The following table provides a reconciliation between the non-GAAP measure of net debt to the most directly comparable GAAP measure of long-term debt:

	December 31, 2019	December 31, 2018
($ thousands)		
Long-term debt	**598,031**	801,625
Working capital(1)(2)	**223,352**	(8,545)
Current assets		
Financial instrument commodity contracts	**39,508**	57,192
Current liabilities		
Financial instrument commodity contracts	**(40,568)**	(2,663)
Lease liabilities	**(3,085)**	—
Decommissioning liabilities	**(8,650)**	(11,704)
Net debt	**808,588**	835,905

Note:

(1) Working capital is equal to current assets less current liabilities as presented on the consolidated statement of financial position. Current assets as at December 31, 2019 were $113.3 million compared to current liabilities of $336.7 million. Current assets as at December 31, 2018 were $127.1 million compared to current liabilities of $118.6 million.

(2) Working capital deficiency as at December 31, 2019 includes $207.7 million of the current portion of long-term debt. There was no long-term debt classified as current in the comparative 2018 period.

- **Payout ratio**

Payout ratio is equal to net capital expenditures, decommissioning expenditures and dividends declared, divided by adjusted funds flow.

The payout ratio is a key cash flow measure that is used by management to determine the sustainability of Bonavista's dividend and capital expenditure program.

The below table provides a reconciliation between cash flow from operating activities, the most comparable GAAP measure, to the measure of adjusted funds flow. Adjusted funds flow is the denominator in the calculation of the payout ratio which is then calculated below.

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ thousands)				
Cash flow from operating activities	**47,952**	77,581	**195,736**	291,191
Interest expense(1)	**(9,011)**	(8,553)	**(34,938)**	(35,141)
Decommissioning expenditures	**2,610**	2,198	**9,743**	12,318
Changes in non-cash working capital(2)	**6,151**	(10,151)	**10,431**	(8,773)
Adjusted funds flow	**47,702**	61,075	**180,972**	259,595
Dividends declared	**—**	2,555	**2,558**	10,168
Net capital expenditures	**67,983**	56,430	**174,628**	171,290
Decommissioning expenditures	**2,610**	2,198	**9,743**	12,318
Total	**70,593**	61,183	**186,929**	193,776
Divided by Adjusted funds flow	**47,702**	61,075	**180,972**	259,595
Payout ratio(3)	**148%**	100%	**103%**	75%

Notes:

(1) Accrued interest expense on Bonavista's long-term debt excluding the amortization of debt issuance costs.
(2) Refer to note 10, "Supplemental cash flow information", of the consolidated financial statements.
(3) Bonavista's payout ratio in prior disclosure documents excluded decommissioning expenditures from the numerator, this has been amended to better reflect a measure of sustainability.

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 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. Support capital has been used to define capital expenditures, included in exploration and development expenditures, that are associated with 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(2)
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.

FORWARD-LOOKING STATEMENT ADVISORIES

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 the management of Bonavista. Such financial outlook or future orientated financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

In particular, but without limiting the foregoing, this document contains forward-looking information and statements pertaining to the following:

- Bonavista's expectations regarding the performance of acquired assets and how they will enhance the economic quality and complement future development plans in the West Central core area;
- Bonavista's expectations regarding the Duvernay resource play and its ability to learn from industry and allocate capital in the next five-years;
- Bonavista's ability to create future shareholder value;
- Bonavista's future expectations with respect to the energy landscape in North America;
- Bonavista's expectations regarding industry conditions, future commodity prices; demand for energy and natural gas and the impact of LNG on GHG emissions;
- Bonavista's expectations regarding our ability to be active in merger and acquisition market;
- Bonavista's expectation that acquisition and divestitures transactions will generate long-term shareholder value;
- Bonavista's 2020 capital expenditure budget and plans;
- Bonavista's expectations for 2019 for production volumes, adjusted funds flow, net debt and payout ratio;
- Bonavista's expectations of future production rates, volumes and production mixes;
- projections of market prices and costs, and exchange and inflation rates;
- the benefits to be obtained from Bonavista's natural gas marketing strategy;
- expectations regarding Bonavista's future decommissioning expenditures;
- the sources of funding Bonavista's abandonment and reclamation program and capital expenditures;
- Bonavista's expectations regarding covenant relief negotiations;
- Bonavista's expectations regarding the funding of the current portion of long-term debt and 2020 capital program;
- Bonavista's expectations regarding the quality, predictability, resilience and sustainability of our asset base;
- the performance characteristics of Bonavista's oil and natural gas properties;
- Bonavista's exploration and development plans and the results therefrom;
- Bonavista's expectations regarding reserves volumes, reserve values, reserve life index, future development costs and decline rates;
- expectations regarding the number and quality of Bonavista's undeveloped locations; and
- Bonavista's focus on creating incremental financial flexibility; and,
- the impact of certain future accounting policies on Bonavista's financial statements.

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 Bonavista's control, including the impact of general economic assumptions and conditions, industry assumptions and conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, changes in environmental tax and royalty legislation, 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. Bonavista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements or if any of them do so, what benefits that Bonavista will derive there from. Bonavista disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

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 document 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.

MANAGEMENT'S REPORT

The Consolidated Financial Statements of Bonavista Energy Corporation and related financial information were prepared by, and are the responsibility of Management. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards. The Consolidated Financial Statements and related financial information reflect amounts which must of necessity be based upon informed estimates and judgments of Management with appropriate consideration to materiality. The Corporation has developed and maintains systems of controls, policies and procedures in order to provide reasonable assurance that assets are properly safeguarded, and that the financial records and systems are appropriately designed and maintained, and provide relevant, timely and reliable financial information to Management.

The Consolidated Financial Statements have been audited by KPMG LLP, the external auditors, in accordance with auditing standards generally accepted in Canada on behalf of the shareholders.

The Board of Directors has established an Audit Committee. The Audit Committee reviews with Management and the external auditors any significant financial reporting issues, the Consolidated Financial Statements, and any other matters of relevance to the parties. The Audit Committee meets quarterly to review and approve the consolidated financial statements prior to their release, as well as annually to review the Corporation's annual Consolidated Financial Statements and Management's Discussion and Analysis and to recommend their approval to the Board of Directors.

The external auditors have unrestricted access to the Corporation, the Audit Committee and the Board of Directors.

Jason E. Skehar	Dean M. Kobelka
President and Chief Executive Officer	Vice President, Finance and Chief Financial Officer

February 13, 2020
Calgary, Alberta

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Bonavista Energy Corporation

Opinion

We have audited the consolidated financial statements of Bonavista Energy Corporation (the "Company"), which comprise:

- the consolidated statements of financial position as at December 31, 2019 and December 31, 2018
- the consolidated statements of income (loss) and comprehensive income (loss) for the years then ended
- the consolidated statements of changes in equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2019 and December 31, 2018, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "*Auditors' Responsibilities for the Audit of the Financial Statements*" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Material Uncertainty Related to Going Concern

We draw attention to note 2 in the financial statements, which indicates that the Company is forecasting a potential breach of certain debt covenants within the next six months that may result in the bank credit facility and senior unsecured notes becoming due on demand.

As stated in note 2 in the financial statements, these events or conditions, along with other matters as set forth in note 2 in the financial statements, indicate that a material uncertainty exists that may cast significant doubt on the Company's ability to continue as a going concern.

Our opinion is not modified in respect of this matter.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditors' report thereon, included in the 2019 Annual Report.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions and the 2019 Annual Report as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

– Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

– The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

– Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

– Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

– Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.

– Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

– Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

– Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is Brad William Robertson.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
February 13, 2020

BONAVISTA ENERGY CORPORATION

Consolidated Statements of Financial Position

As at December 31	Note	2019	2018
($ thousands)			
Assets			
Current assets			
Accounts receivable		**59,753**	54,711
Prepaid expenses and other assets		**14,086**	13,993
Financial instrument commodity contracts	(6)	**39,508**	57,192
Financial instrument contracts	(6)	**—**	1,200
		113,347	127,096
Financial instrument commodity contracts	(6)	**14,789**	19,898
Financial instrument contracts	(6)	**—**	17,204
Property, plant and equipment	(12)	**2,245,876**	2,633,494
Exploration and evaluation assets	(13)	**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	(15)	**207,736**	—
Current portion of decommissioning liabilities	(16)	**8,650**	11,704
Dividends payable		**—**	2,555
Financial instrument commodity contracts	(6)	**40,568**	2,663
Financial instrument contracts	(6)	**542**	—
		336,699	118,551
Financial instrument commodity contracts	(6)	**26,634**	5,226
Financial instrument contracts	(6)	**138**	—
Long-term debt	(15)	**598,031**	801,625
Other long-term liabilities		**2,120**	4,070
Decommissioning liabilities	(16)	**361,918**	419,042
Deferred income taxes	(18)	**—**	23,011
Total liabilities		**1,325,540**	1,371,525
Shareholders' equity	(14)		
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

Future operations (note 2), Subsequent events (note 6), and Commitments (note 19).
See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors of Bonavista Energy Corporation,

Ian S. Brown, Director

David P. Carey, Director

BONAVISTA ENERGY CORPORATION

Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)

For the years ended December 31	Note	2019	2018
($ thousands, except per share amounts)			
Revenues			
Production	(7)	**372,405**	514,967
Royalties		**(17,377)**	(34,360)
Production revenues, net of royalties		**355,028**	480,607
Financial instrument commodity contracts			
Realized gains on financial instrument commodity contracts	(6)	**49,940**	16,083
Unrealized gains (losses) on financial instrument commodity contracts	(6)	**(82,106)**	43,014
Production revenues, net of royalties and financial instrument commodity contracts		**322,862**	539,704
Expenses			
Operating		**133,312**	143,935
Transportation		**32,490**	33,728
General and administrative		**20,577**	24,291
Share-based compensation	(14)	**9,961**	10,381
Loss on disposition of property, plant and equipment		**15,337**	6,725
Loss (gain) on disposition of exploration and evaluation assets		**1,772**	(167)
Depletion, depreciation, amortization and impairment	(12)	**499,290**	227,447
Net finance costs	(2)(9)	**23,131**	66,450
Total expenses		**735,870**	512,790
Income (loss) before taxes		**(413,008)**	26,914
Deferred income tax expense (recovery)	(18)	**(23,011)**	15,099
Net income (loss) and comprehensive income (loss)		**(389,997)**	11,815
Net income (loss) per share			
Basic	(14)	**(1.48)**	0.05
Diluted	(14)	**(1.48)**	0.04

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY CORPORATION
Consolidated Statements of Changes in Equity

($ thousands)	Shareholders' Capital	Exchangeable Shares	Contributed Surplus	Deficit	Total Shareholders' Equity
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
Net loss	**—**	**—**	**—**	**(389,997)**	**(389,997)**
Conversion of restricted incentive and performance incentive awards	**10,550**	**—**	**(10,550)**	**—**	**—**
Share-based compensation expense	**—**	**—**	**9,548**	**—**	**9,548**
Share-based compensation capitalized	**—**	**—**	**580**	**—**	**580**
Exchangeable shares exchanged for common shares	**454**	**(454)**	**—**	**—**	**—**
Dividends declared	**—**	**—**	**—**	**(2,558)**	**(2,558)**
Balance as at December 31, 2019	**2,881,935**	**88,963**	**52,746**	**(1,853,887)**	**1,169,757**

See accompanying notes to the consolidated financial statements.

BONAVISTA ENERGY CORPORATION

Consolidated Statements of Cash Flows

For the years ended December 31	Note	2019	2018
($ thousands)			
Cash provided by (used in):			
Operating Activities			
Net income (loss)		**(389,997)**	11,815
Adjustments for:			
Depletion, depreciation, amortization and impairment		**499,290**	227,447
Share-based compensation		**9,548**	10,381
Unrealized losses (gains) on financial instrument commodity contracts		**82,106**	(43,014)
Loss on disposition of property, plant and equipment		**15,337**	6,725
Loss (gain) on disposition of exploration and evaluation assets		**1,772**	(167)
Net finance costs		**20,865**	66,450
Deferred income tax expense (recovery)		**(23,011)**	15,099
Decommissioning expenditures		**(9,743)**	(12,318)
Changes in non-cash working capital items	(10)	**(10,431)**	8,773
Cash flow from operating activities		**195,736**	291,191
Financing Activities			
Dividends paid		**(5,113)**	(10,131)
Interest paid		**(35,406)**	(32,951)
Lease payments	(17)	**(5,178)**	—
Monetization of financial instrument contracts	(9)	**5,857**	—
Net proceeds (repayment) of long-term debt		**40,172**	(60,015)
Cash flow from (used in) financing activities		**332**	(103,097)
Investing Activities			
Exploration and development		**(139,550)**	(164,492)
Property acquisitions		**(55,395)**	(32,654)
Property dispositions		**21,472**	26,616
Office equipment		**(1,155)**	(760)
Changes in non-cash working capital items	(10)	**(21,440)**	(16,804)
Cash flow used in investing activities		**(196,068)**	(188,094)
Change in cash		**—**	—
Cash, beginning of year		**—**	—
Cash, end of year		**—**	—

See accompanying notes to the consolidated financial statements.

1. Structure of the Corporation

The principal undertakings of Bonavista Energy Corporation (the “Corporation” or “Bonavista”) are to carry on the business of acquiring, developing and holding interests in natural gas, natural gas liquids and oil properties and assets in Western Canada.

Bonavista's principal place of business is located at 1500, 525 - 8th Avenue SW, Calgary, Alberta, Canada T2P 1G1.

The audited consolidated financial statements of the Corporation as at and for the year ended December 31, 2019, are available on SEDAR at www.sedar.com or can be obtained from Bonavista’s website at www.bonavistaenergy.com.

2. Future operations

As at December 31, 2019, Bonavista had a working capital deficiency, however, was in compliance with all financial covenants on its bank credit facility and senior unsecured notes. Management's forecasts for 2020 based upon current strip pricing, indicates a potential breach of its total debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment ("EBITDA") and senior debt to EBITDA covenants within the next six months. Management forecasts may change materially based upon actual prices received during the year, changes in future strip pricing and its future business plan. If these financial covenants are not met, the bank credit facility and senior unsecured notes may become due on demand. This material uncertainty may cast significant doubt with respect to the ability of the Corporation to continue as a going concern.

Bonavista is in the process of negotiating covenant relief from its senior noteholders and members of its bank credit facility. No agreements have been reached as of the date of the consolidated financial statements and therefore, there can be no assurance that such agreements will be reached. Bonavista does, however, expect that this negotiation process will be successful and suitable terms for covenant relief reached. Since the commencement of the negotiation process, Bonavista has spent $2.3 million on professional fees rendered on behalf of itself and its creditors, which has been included in finance expenses on the statement of income (loss) and comprehensive income (loss).

The consolidated financial statements have been prepared on a going concern basis, which presumes that Bonavista will continue its operations for the foreseeable future and will be able to realize its assets and discharge its liabilities and commitments in the normal course of business. The consolidated financial statements do not reflect adjustments and classifications of assets, liabilities, revenues and expenses which, would be necessary if the Corporation were unable to continue as a going concern.

3. Basis of presentation

Statement of compliance

The consolidated financial statements (the "financial statements") have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). A summary of Bonavista's significant accounting policies under IFRS are presented in note 5, "Significant accounting policies". These accounting policies have been applied consistently for all periods presented in these financial statements, with the exception of the impact from the adoption of new accounting standards as described in note 4, "Changes in accounting policies".

These financial statements were authorized for issue by the Corporation's Board of Directors' on February 13, 2020.

Basis of measurement

These financial statements have been prepared on the historical cost basis except for derivative financial instruments, which are measured at fair value.

Functional and presentation currency

These financial statements are presented in Canadian dollars ("CDN"), which is the Corporation's functional currency.

Use of management's judgments and estimates

The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any, as at the date of the financial statements and the reported amounts of revenue and expenses during the period. Estimates are subject to measurement uncertainty and changes in such estimates in future years could require a material change in the financial statements. These underlying assumptions are based on historical experience and other factors that management believes to be reasonable under the circumstances, and are subject to change as new events occur, as more industry experience is acquired, as additional information is obtained and as Bonavista's operating environment changes.

Estimates and underlying assumptions are reviewed on an ongoing basis by management. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected. The key sources of estimation uncertainty to the carrying amounts of assets and liabilities are discussed below:

i. Determination of a Cash-Generating Unit (“CGU”)

   The determination of Bonavista’s CGUs is subject to management’s judgment. In determining Bonavista’s CGUs, management assessed what constituted independent cash flows and how to aggregate the respective assets. The asset composition of each CGU can directly impact the assessment of the recoverability of those assets included within each CGU. Bonavista's current CGU composition includes its British Columbia CGU, Deep Basin CGU and West Central CGU.

ii. Impairment testing

   Bonavista assesses its property, plant and equipment for impairment when events or circumstances indicate that the carrying amount of its assets may not be recoverable. If any indication of impairment exists, Bonavista performs an impairment test on the CGU, which is the lowest level at which there are identifiable cash flows. The carrying amount of each CGU is compared to its recoverable amount which is defined as the greater of its fair value less costs of disposal and value in use and is subject to management estimates. Bonavista also assesses its property, plant and equipment to determine if events or circumstances would support the reversal of any previously recorded impairment charges. In this assessment Bonavista considers the facts and circumstances that caused the original impairment charge to be recognized and whether there is a sustained period in which those facts and circumstances changed.

iii. Proved plus probable oil and natural gas reserves

   Reserve estimates are based on engineering data, estimated future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to interpretation and uncertainty. Bonavista expects that over time its reserve estimates will be revised either upward or downward depending upon the factors as stated above. These reserve estimates can have a significant impact on net income (loss), as it is a key component in the calculation of depletion, depreciation and amortization, and also for the determination of potential asset impairments or reversals.

iv. Depreciation, depletion, amortization and impairment

   Property, plant and equipment is measured at cost less accumulated depreciation, depletion, amortization and impairment. Bonavista’s oil and natural gas properties are depleted using the unit-of-production method over proved plus probable reserves for each CGU. The unit-of-production method takes into account estimates of capital expenditures incurred to date along with future development capital required to develop both proved and probable reserves.

v. Decommissioning liability

   The provision for decommissioning liabilities is based on management's estimates of costs and planned remediation projects. Actual costs may differ from those estimated due to changes in governing environment laws and regulations, technological changes, and market conditions. The estimate for decommissioning liabilities is also impacted by the risk-free and inflation rates used to estimate the present value of the decommissioning liability, refer to note 16, "Decommissioning liabilities".

vi. Financial instrument contracts

   The estimated fair value of financial instrument commodity contracts are subject to changes in forward looking commodity prices, interest rate curves, volatility curves and counterparty non-performance risk. The estimated fair values of the Corporation’s financial instrument contracts are subject to changes in foreign exchange rates.

4. Changes in accounting policies

a. Adoption of IFRS 16, "Leases"

Effective January 1, 2019, Bonavista adopted IFRS 16 *Leases* ("IFRS 16"), which replaced IAS 17 *Leases.* The Corporation has applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. On adoption, the Corporation elected to use the following practical expedients permitted under the standard:

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Account for leases with a remaining term of less than twelve months as at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use asset if the underlying asset is of low dollar value (less than US$5 thousand); and
- The use of hindsight in determining the lease term where the contract contains terms to extend or terminate the lease.

The cumulative effect of initially applying the standard was recognized as a $6.4 million right-of-use asset (included in "property, plant and equipment") and an $8.9 million lease obligation (included in "accounts payable and accrued liabilities" and "other long-term liabilities"). The right-of-use assets recognized were measured at amounts equal to the present value of the lease obligations less lease incentives received. The weighted average incremental borrowing rate used to determine the lease obligations at adoption was approximately 4.30%. The right-of-use assets and lease obligations recognized relate to the Corporation's head office lease in Calgary, field equipment and certain vehicles.

The following table shows the impact of the implementation of IFRS 16 on the operating lease commitments previously disclosed in note 19, "Contractual obligations and commitments".

	As at January 1, 2019
($ thousands)	
Office lease(1)	10,703
Reduction in office lease commitment(2)	(1,511)
Non-lease components	(2,361)
Lease component of lease commitments	6,831
Impact of discounting	(231)
Office lease liability recognized	6,600

Notes:

(1) Office lease expires July 31, 2020.
(2) Pertains to a reduction in Bonavista's net rentable area.

The financial statement impact of IFRS 16 is subject to certain management judgments and estimates. Specifically, extension and termination provisions are included in certain lease contracts. In determining the lease term to be recognized, management considers all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. In addition, the measurement of lease obligations is subject to management's judgment in the determination of the applicable incremental borrowing rate.

b. Adoption of Deferred Share Unit Plan

In 2019, Bonavista adopted a deferred share unit ("DSU") plan primarily for non-management directors and non-executive officers which entitles participants to receive cash, based on the trading price of the Corporation's common shares on the payment date. Deferred share units can only be redeemed following the participants departure from the Corporation and must be redeemed prior to December 1st of the year following the departure date. A liability for the expected cash payments is accrued over the life of the deferred share unit based on the closing price of the Corporation's common shares at each reporting date. Compensation expense is recorded in "share-based compensation" on the Corporation's consolidated statement of income (loss) and comprehensive income (loss).

c. Adoption of amendments to IFRS 3, "Business Combinations"

On October 22, 2018, the IASB issued amendments to the guidance in IFRS 3 *Business Combinations* ("IFRS 3"), revising the definition of a business and providing for the addition of an optional 'concentration test' to determine if the acquisition is a business. To be considered a business under the amendments to IFRS 3, an acquisition would have to include an input and a substantive process that together significantly contribute to the ability to create outputs. The three elements of a business are defined as follows:

- Input - Any economic resource that creates outputs, or has the ability to contribute to the creation of outputs, when one or more processes are applied to it.
- Process - Any system, standard, protocol, convention or rule that, when applied to an input or inputs, creates outputs or has the ability to contribute to the creation of outputs.
- Output - The result of inputs and processes applied to those inputs that provide goods or services to customers, generate investment income or generate other income from ordinary activities.

The optional 'concentration test' permits a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or a group of similar identifiable assets. An entity may elect to apply, or not apply, the test. An entity may make such an election separately for each transaction or other event. If the concentration test is met, the sets of activities and assets is determined not to be a business and no further assessment is needed.

The amendments to IFRS 3 apply to businesses acquired in annual reporting periods beginning on or after January 1, 2020, with early adoption permitted. Bonavista has chosen to early adopt the amendments to IFRS 3 effective January 1, 2019 and apply to these financial statements, refer to note 11, "Property acquisitions".

5. Significant accounting policies

Basis of consolidation

The consolidated financial statements comprise the financial statements of Bonavista and its subsidiaries as at December 31, 2019. Subsidiaries are consolidated from the date of acquisition, being the date on which Bonavista obtains control, and continues to be consolidated until the date that control ceases. Control exists when Bonavista has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. All intercompany balances and transactions, and any unrealized income and expenses, arising from intercompany transactions are eliminated in full.

Many of Bonavista's oil and natural gas activities involve jointly controlled assets. The financial statements include Bonavista's share of these jointly controlled assets and a proportionate share of the relevant revenue and related costs.

Business combinations

Bonavista evaluates each transaction or event separately which may result in either the application of accounting for a business combination or asset acquisition. Business combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in net income or loss. Transaction costs associated with a business combination are expensed as incurred.

Bonavista may elect for each transaction or event to apply an optional 'concentration test' which permits a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets is concentrated in a single identifiable asset or group of similar identifiable assets. If the transaction is determined to be an asset acquisition, the purchase price is allocated to the identifiable assets and liabilities based on their relative fair values at the acquisition date. Transaction costs associated with an asset acquisition are capitalized.

Foreign currency

Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets and liabilities denominated in foreign currencies that are measured at fair value are translated at the functional currency at the exchange rate at the date that the fair value was determined. Foreign currency differences arising on translation are recognized in the consolidated statement of income (loss) and comprehensive income (loss).

Financial instruments

Financial instruments are recognized when Bonavista becomes a party to the contractual provisions of the instrument. Financial assets and liabilities are offset and the net amount is presented in the consolidated statement of financial position when, and only when, Bonavista has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

Classification and Measurement of Financial Assets

The initial classification of a financial asset depends on Bonavista's business model for managing its financial assets and the contractual terms of the cash flows. There are three measurement categories into which Bonavista classifies its financial assets:

- Amortized cost - Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flow that represent solely payments of principal and interest;
- Fair value through other comprehensive income ("FVOCI") - Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest; or
- Fair value through profit or loss ("FVTPL") - Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss. This includes all derivative financial assets.

Bonavista initially recognizes loans, receivables and deposits on the date that they originated. All other financial assets (including assets designated at fair value through profit or loss) are recognized initially on the date at which Bonavista becomes a party to the contractual provisions of the instrument.

Bonavista derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred. Any interest in transferred financial assets that is created or retained by Bonavista is recognized as a separate asset or liability.

Impairment of financial assets

Bonavista recognizes loss allowances for expected credit losses ("ECLs") on its financial assets measured at amortized cost. Due to the nature of its financial assets, Bonavista measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset.

Classification and Measurement of Financial Liabilities

Bonavista initially recognizes debt securities issued and subordinated liabilities on the date that they originated. All other financial liabilities (including liabilities designated at FVTPL) are recognized initially on the trade date at which Bonavista becomes a party to the contractual provisions of the instrument.

Bonavista initially classifies financial liabilities as measured at amortized cost or FVTPL. A financial liability is classified as measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable. Financial liabilities at FVTPL (other than financial liabilities designated at FVTPL) are measured at fair value with changes in fair value, along with any interest expense, recognized in the consolidated statement of income (loss). Other financial liabilities are initially measured at fair value less attributable transaction costs and are subsequently measured at amortized cost using the effective interest method.

Bonavista derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired. Any gain or loss on derecognition is recognized in the consolidated statement of income (loss) and comprehensive income (loss).

Derivative financial instruments

Bonavista has entered into certain derivative financial instruments to manage the exposure to market risks from fluctuations in commodity prices and foreign exchange rates. These derivative financial instruments are not used for trading or speculative purposes. Bonavista has not designated its derivative financial instruments as effective accounting hedges, and thus has not applied hedge accounting, even though the Corporation considers all commodity contracts and foreign exchange contracts to be economic hedges. Derivative financial instruments are classified and measured at FVTPL and any attributable transaction costs are recognized in profit or loss when incurred. Subsequent to initial recognition, derivative financial instruments are measured at fair value, and changes therein are recognized immediately in profit or loss. The estimated fair value of all derivative financial instruments is based on quoted market prices or, in their absence, third party market indications and forecasts.

Bonavista has accounted for its forward physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery, of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the consolidated statement of financial position. Settlements on these physical sales contracts are recognized in production revenues.

Exploration and evaluation assets and property, plant and equipment

Exploration and evaluation expenditures

Exploration and evaluation ("E&E") costs, including the costs of acquiring licences and directly attributable general and administrative costs are initially capitalized as either tangible or intangible E&E assets according to the nature of the assets acquired. Pre-licence costs are recognized in the consolidated statement of income (loss) and comprehensive income (loss) as incurred. The costs are accumulated in cost centres by well, field or exploration area pending determination of technical feasibility and commercial viability.

The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when total proved plus probable reserves are determined to exist. Annually, a review of each exploration licence or field is carried out, to ascertain whether proved plus probable reserves have been discovered. Upon determination of total proved plus probable reserves, intangible E&E assets attributable to those reserves are transferred from E&E assets to a separate category within tangible assets referred to as oil and natural gas properties.

Gains and losses on dispositions of exploration and evaluation assets, are determined by comparing the proceeds from disposal with the carrying amount of exploration and evaluation assets and are recognized on a net basis within "gain (loss) on disposition of exploration and evaluation assets" in the consolidated statement of income (loss) and comprehensive income (loss).

Development and production costs

Items of property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as oil and natural gas interests only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in profit or loss as incurred. Such capitalized oil and natural gas interests generally represent costs incurred in developing proved or proved plus probable reserves and bringing in or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. The carrying amount of any replaced or sold component is derecognized. The costs of the day-to-day servicing of property, plant and equipment are recognized in the consolidated statement of income (loss) and comprehensive income (loss) as incurred.

Gains and losses on dispositions of property, plant and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recognized on a net basis within "gain (loss) on disposition of property, plant and equipment" in the consolidated statement of income (loss) and comprehensive income (loss).

Depletion, depreciation and amortization

The net carrying amount of development or production assets is depleted using the unit-of-production method by reference to the ratio of production in the year to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. Future development costs are estimated taking into account the level of development required to produce the reserves. These estimates are reviewed by independent reserve engineers at least annually.

Proved plus probable reserves are estimated using independent reserve engineering reports and represent the estimated quantities of oil, natural gas liquids and natural gas, which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50% statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved plus probable and a 50% statistical probability that it will be less. The equivalent statistical probabilities for the proven component of proved plus probable reserves are 90% and 10%, respectively.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon:

- a reasonable assessment of the future economics of such production;
- a reasonable expectation that there is a market for all or substantially all the expected oil and natural gas production; and
- evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Reserves may only be considered total proved plus probable if producibility is supported by either actual production or conclusive formation test. The area of reservoir considered proved includes: (a) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, or both; and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geophysical, geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of oil and natural gas controls the lower proved limit of the reservoir.

Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are only included in the proved plus probable classification when successful testing by a pilot project, the operation of an installed program in the reservoir, or other reasonable evidence (such as, experience of the same techniques on similar reservoirs or reservoir simulation studies) provides support for the engineering analysis on which the project or program was based.

The estimated useful lives for certain production assets for the current and comparative years are as follows:

Facilities	15 years
Oil and natural gas properties	Based on CGU Reserve Life

For other assets, depreciation is recognized in profit or loss on a straight-line basis over the estimated useful lives of each part of an item of property, plant and equipment. Depreciation methods, useful lives and residual values are reviewed at each reporting date.

The estimated useful lives for other assets for the current and comparative years are as follows:

Office equipment	5 years
Fixtures and fittings	5 years
Leaseholds	9.5 years

Other intangible assets that are acquired by Bonavista, which have finite useful lives, are measured at cost less accumulated amortization and accumulated impairment losses. Subsequent expenditure is capitalized only when it increases the future economic benefits embodied in the specific asset to which it relates. Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of other intangible assets, other than goodwill, from the date they were available for use.

Impairment

Exploration and evaluation ("E&E") assets

E&E assets are assessed for impairment at the operating segment level and tested for impairment when circumstances arise which could indicate potential impairment. Upon determination of technical feasibility and commercial viability, the E&E assets are first tested for impairment by comparing the carrying amount to the greater of the E&E assets' fair value less cost of disposal or value in use and then transferred to a separate category within tangible assets referred to as oil and natural gas properties. An impairment charge on E&E assets is recognized if the carrying value of the E&E assets exceeds the recoverable amount. Any impairment charge is recognized in the consolidated statement of income (loss) and comprehensive income (loss) in depletion, depreciation, amortization and impairment.

If there is an indication that a previously recognized impairment charge may no longer exist or may have decreased, the recoverable amount of the relevant E&E asset is calculated and compared against the carrying amount. An impairment charge is reversed to the extent that the asset's recoverable amount does not exceed the carrying amount that would have been determined if no impairment charge had been recognized.

Development and production assets

For the purpose of impairment testing, Bonavista's development and production assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets, the CGU. CGUs are reviewed at each reporting date to determine whether there is any indication of impairment or impairment reversals. If any such indication exists, an impairment test is performed by comparing the CGUs carrying value to its recoverable amount, defined as the greater of a CGU's fair value less costs of disposal and value in use. Any excess of carrying value over the recoverable amount is recognized in the consolidated statement of income (loss) and comprehensive income (loss) in depletion, depreciation, amortization and impairment.

If there is an indication that a previously recognized impairment charge may no longer exist or may have decreased, the recoverable amount of the relevant CGU is calculated and compared against the carrying amount. An impairment charge is reversed to the extent that the asset's recoverable amount does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment charge had been recognized. A reversal of an impairment charge is recognized in the consolidated statement of income (loss) and comprehensive income (loss) in depletion, depreciation, amortization and impairment.

Employee benefits

Share-based compensation

Long-term incentives are granted to officers, directors, employees and certain consultants in accordance with Bonavista's restricted incentive award and performance incentive award plans.

The fair value of restricted incentive awards is assessed on the grant date factoring in the weighted average trading price of the five days preceding the grant date and forecasted dividends. This fair value is recognized as compensation expense over the vesting period with a corresponding increase in contributed surplus. Upon the conversion of the restricted incentive awards or the settlement of the incentive awards by common shares, on the predetermined vesting dates, the value in contributed surplus pertaining to the awards is recorded as shareholders’ capital. Restricted incentive awards vest on terms up to three years from the initial date of grant as determined by Bonavista's Board of Directors.

The fair value of performance incentive awards is assessed on grant date by using the closing price of common shares and multiplied by the estimated performance multiplier. The performance multiplier can range from 0 to 2 and is dependent on the performance of the Corporation at the end of the vesting period relative to corporate performance measures determined at the discretion of Bonavista's Board of Directors. The fair value is recognized as compensation expense over the vesting period with a corresponding increase to contributed surplus. Upon settlement of the performance incentive awards by common shares, on the predetermined payment date, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital. Performance incentive awards vest thirty-nine months from the initial date of grant as determined by Bonavista's Board of Directors.

Under the long-term incentive plans, forfeiture rates are assigned at the grant date and upon vesting, the difference between estimated and actual forfeitures is adjusted through share-based compensation.

Cash-based compensation

Long-term deferred share units are granted to non-management directors and non-executive officers in accordance with Bonavista's deferred share unit plan.

Bonavista's DSU plan entitles participates to receive cash based on the Corporation's weighted average trading price of the five days preceding the redemption date. Deferred share units can only be redeemed following the participants departure from the Corporation and must be redeemed prior to December 1st of the year following the departure date. A liability for the expected cash payments is accrued over the life of the deferred share unit based on the closing price of the Corporation's common shares at each reporting date. Compensation expense is recorded in the consolidated statement of income (loss) and comprehensive income (loss) as share-based compensation.

Short-term employee benefits

Short-term employee benefit obligations are expensed as the related service is provided. A liability is recognized for the amount expected to be paid under short-term cash bonus or profit-sharing plans if Bonavista has a present legal or constructive obligation to pay this amount as a result of past service provided by the employee, and the obligation can be estimated reliably.

Lease payments

Leases are recognized as a right-of-use asset and a corresponding lease liability at the date on which the leased asset is available for use by Bonavista. Assets and liabilities arising from a lease are initially measured on a present value basis. Lease liabilities include the net present value of fixed payments, variable lease payments that are based on an index or a rate, amounts expected to be paid by the lessee under residual value guarantees, the exercise price of purchase options if the lessee is reasonably certain to exercise that option, and payments of penalties for terminating the lease, less any lease incentives receivable. These payments are discounted using Bonavista's incremental borrowing rate when the rate implicit in the lease is not readily available. Bonavista uses a single discount rate for a portfolio of leases with reasonably similar characteristics.

Lease payments are allocated between the lease liability and finance costs. The finance cost is charged to net income over the lease term. The lease liability is measured at amortized cost using the effective interest method. It is remeasured when there is a change in the future lease payments arising from a change in an index or rate, if there is a change in the amount expected to be payable under a residual value guarantee or if there is a change in the assessment of whether Bonavista will exercise a purchase, extension or termination option that is within the control of the Corporation. When the lease liability is remeasured, a corresponding adjustment is made to the carrying amount of the right-of-use asset or is recorded in the consolidated statement of income (loss) if the carrying amount of the right-of-use asset has been reduced to zero.

The right-of-use asset is initially measured at cost, which comprises the initial amount of the lease liability, any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset. The right-of-use asset is depreciated, on a straight-line basis, over the shorter of the estimated useful life of the asset or the lease term. The right-of-use asset may be adjusted for certain remeasurements of the lease liability and impairment losses.

Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the consolidated statement of income (loss) and comprehensive income (loss) on a straight-line basis over the lease term.

Provisions

A provision is recognized if, as a result of a past event, Bonavista has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

Decommissioning liabilities

Bonavista's activities give rise to dismantling, decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning liabilities are measured at the present value of management’s best estimate of expenditure required to settle the present obligation at the date of the consolidated statement of financial position. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time is recognized as finance costs whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

Revenues

Bonavista’s production revenues from the sale of crude oil, natural gas liquids and natural gas are based on the consideration specified in contracts with customers. Bonavista recognizes revenue when it transfers control of the product to the customer, which is generally when legal title passes to the customer which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured. The amount of revenue recognized is based on the consideration specified in the contract.

Bonavista evaluates its arrangements with third parties and partners to determine if Bonavista is acting as the principal or as an agent. Bonavista is considered the principal in a transaction when it has primary responsibility for the transaction. If Bonavista acts in the capacity of an agent rather than as a principal in a transaction, then the revenue is recognized on a net basis, only reflecting the fee, if any, realized by Bonavista from the transaction.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by Bonavista are evaluated by management to determine if they originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Finance income and costs

Finance costs comprise of interest expense on borrowings, unwinding of the discount on provisions and impairment losses recognized on financial assets. Fair value losses on financial assets are recognized in the consolidated statement of income (loss) and comprehensive income (loss).

Interest income is recognized as it accrues in the consolidated statement of income (loss) and comprehensive income (loss), using the effective interest method.

Foreign currency gains and losses are reported under finance income or expenses.

Income taxes

Income tax expense comprises current and deferred income taxes. Current and deferred income taxes are recognized in the consolidated statement of income (loss) except to the extent that it relates to a business combination, or items recognized directly in equity or in other comprehensive income (loss).

Current tax is the expected tax payable or receivable on the taxable income or loss for the period, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred income taxes are recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred income taxes are not recognized for:

- temporary differences on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss;
- temporary differences related to investments in subsidiaries to the extent that it is probable that they will not reverse in the foreseeable future; and
- taxable temporary differences arising on the initial recognition of goodwill.

Deferred income taxes are measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

Deferred income tax assets and liabilities are offset if there is a legally enforceable right to offset current tax liabilities and assets, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred income tax asset is recognized for unused tax losses, tax credits and deductible temporary differences, to the extent that it is probable that future taxable profits will be available against which they can be utilized. Deferred income tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Per share amounts

Basic per share amounts are calculated by dividing net income (loss) attributable to common shareholders of Bonavista by the weighted average number of common shares outstanding during the period. Diluted per share amounts are determined by adjusting net income (loss) attributable to common shareholders and the weighted average number of common shares outstanding for the effects of dilutive instruments such as stock options, restricted incentive awards and performance incentive awards granted to employees.

6. Financial risk management

To manage its exposure to certain market risks, Bonavista has a risk management program in place which includes financial instruments as disclosed in the commodity price risk and foreign exchange risk sections of this note. The objective of Bonavista's risk management program is to mitigate exposure to fluctuations in commodity prices, interest rates and foreign exchange rates to reduce volatility in the Corporation's adjusted funds flow as defined in note 8, "Capital management".

Commodity price risk

Bonavista is exposed to commodity price risk as prices received for its natural gas, natural gas liquids and oil production fluctuate. Commodity prices fluctuate as a result of a number of local and global factors including, supply and demand, inventory levels, weather patterns, pipeline transportation constraints, political stability and economic factors. Bonavista mitigates a portion of the commodity price risk through the use of various financial instrument commodity contracts and physical delivery sales contracts. Bonavista's policy is to enter into commodity price contracts when considered appropriate to a maximum of 70% of forecasted production volumes for the subsequent twelve month period, 60% in years two and three and 25% in years four and five, provided that no more than 80% of forecasted production volumes from any one product (where natural gas and ethane are considered as one product, propane is considered to be its own product and butane, condensate and oil are considered one product) may be hedged, or in the case of electricity, 60% of Bonavista's forecasted net consumption. The term of any commodity hedge executed will be limited to no more than five calendar years subsequent to the current calendar year. Bonavista's management regularly reviews this policy to reflect changes in market conditions.

Financial instrument commodity contracts

As at December 31, 2019, Bonavista had entered into the following costless collars to sell oil:

Volume		Average Price	Contract	Term
Oil contracts				
500	bbls/d	CDN $67.50 - CDN $73.01	WTI - Costless Collar	January 1, 2020 - December 31, 2020

As at December 31, 2019, Bonavista had entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
Natural gas				
30,000	gj/d	CDN $2.01	AECO - Swap	January 1, 2020 - March 31, 2020
10,000	gj/d	CDN $1.67	AECO - Swap	January 1, 2020 - December 31, 2020
65,000	gj/d	CDN $1.53	AECO - Swap	April 1, 2020 - October 31, 2020
15,000	gj/d	CDN $1.81	AECO - Swap	January 1, 2021 - December 31, 2021
35,000	gj/d	CDN $1.67	AECO - Swap	April 1, 2021 - October 31, 2021
30,000	mmbtu/d	US ($1.15)	AECO - Basis Swap	January 1, 2020 - March 31, 2020
10,000	mmbtu/d	US ($0.98)	AECO - Basis Swap	January 1, 2020 - December 31, 2021
30,000	mmbtu/d	US ($1.36)	AECO - Basis Swap	April 1, 2020 - October 31, 2020
20,000	mmbtu/d	US ($1.16)	AECO - Basis Swap	November 1, 2020 - March 31, 2021
40,000	mmbtu/d	US ($1.29)	AECO - Basis Swap	April 1, 2021 - October 31, 2021
10,000	mmbtu/d	US ($1.16)	AECO - Basis Swap	November 1, 2021 - March 31, 2022
30,000	mmbtu/d	US ($1.36)	AECO - Basis Swap	April 1, 2022 - October 31, 2022
15,000	mmbtu/d	US ($0.08)	DAWN - Basis Swap	January 1, 2020 - December 31, 2021
20,000	mmbtu/d	US ($0.16)	CHICAGO - Basis Swap	January 1, 2020 - March 31, 2024
10,000	mmbtu/d	US $2.84	NYMEX - Swap	January 1, 2020 - March 31, 2020
10,000	mmbtu/d	US $2.77	NYMEX - Swap	January 1, 2020 - October 31, 2020
35,000	mmbtu/d	US $2.75	NYMEX - Swap	January 1, 2020 - December 31, 2020
5,000	mmbtu/d	US $2.27	NYMEX - Swap	April 1, 2020 - October 31, 2020
10,000	gj/d	CDN $1.75	AECO - Sold Call	January 1, 2020 - December 31, 2020
10,000	gj/d	CDN $1.80	AECO - Sold Call	January 1, 2021 - December 31, 2021
10,000	mmbtu/d	US $3.75	NYMEX - Sold Call	January 1, 2020 - December 31, 2021

Natural gas liquids				
250	bbls/d	US $34.86	MTB BT - Swap	January 1, 2020 - December 31, 2020
250	bbls/d	US $34.86	MTB BT - Swap	April 1, 2020 - December 31, 2020

Oil				
750	bbls/d	CDN $80.57	WTI - Swap	January 1, 2020 - March 31, 2020
1,750	bbls/d	CDN $79.06	WTI - Swap	January 1, 2020 - December 31, 2020
750	bbls/d	CDN $77.14	WTI - Swap	January 1, 2021 - December 31, 2021
1,000	bbls/d	CDN $90.00	WTI - Sold Call	January 1, 2020 - December 31, 2020
1,250	bbls/d	US $55.68	WTI - Sold Call	January 1, 2020 - December 31, 2020

Subsequent to December 31, 2019, Bonavista entered into the following contracts to manage its overall commodity exposure:

Volume		Price	Contract	Term
5,000	gj/d	CDN $1.68	AECO - Swap	April 1, 2020 - October 31, 2020
15,000	gj/d	CDN $1.71	AECO - Swap	April 1, 2020 - March 31, 2021
15,000	gj/d	CDN $1.32	AECO - Swap	November 1, 2020 - March 31, 2021
5,000	mmbtu/d	US $2.29	NYMEX - Swap	April 1, 2020 - October 31, 2020
250	bbls/d	CDN $76.00	WTI - Swap	April 1, 2020 - March 31, 2021

Bonavista's financial instrument commodity contracts are sensitive to commodity price volatility. The following table highlights the approximate impact that changes in the fair value of the financial instrument commodity contracts would have on net loss and comprehensive loss at December 31, 2019 with changes to the underlying commodity prices.

	Commodity Price Sensitivity	
($ thousands)		
	Increase $0.10	Decrease $0.10
Natural Gas Commodity Contracts	(10,708)	10,708
	Increase $1.00	Decrease $1.00
Natural Gas Liquids Commodity Contracts	(153)	153
	Increase $1.00	Decrease $1.00
Oil Commodity Contracts	(722)	722

Financial instrument commodity contracts are recorded on the consolidated statement of financial position at fair value at each reporting period with the change in fair value being recognized as an unrealized gain or loss on the consolidated statements of income (loss) and comprehensive income (loss).

As at December 31, 2019, the fair value recorded on the consolidated statement of financial position for these financial instrument commodity contracts was a net liability of $12.9 million (December 31, 2018 - $69.2 million, net asset) of which a net liability of $1.1 million (December 31, 2018 - $54.5 million, net asset) relates to financial instrument commodity contracts with term dates within one year and a net liability of $11.8 million (December 31, 2018 - $14.7 million, net asset) relates to financial instrument commodity contracts with term dates beyond one year.

During the year ended December 31, 2019, a net loss of $32.2 million (December 31, 2018 - $59.1 million, net gain) was recorded on the consolidated statement of income (loss) and comprehensive income (loss), consisting of a realized gain of $49.9 million (December 31, 2018 - $16.1 million, realized gain) and an unrealized loss of $82.1 million (December 31, 2018 - $43.0 million, unrealized gain).

Physical purchase and sale contracts

As at December 31, 2019, Bonavista had entered into the following fixed price physical contracts to sell natural gas:

Volume		Price	Contract	Term
30,000	gj/d	CDN $2.13	AECO	January 1, 2020 - March 31, 2020(1)
10,000	gj/d	CDN $1.75	AECO	January 1, 2020 - December 31, 2020(2)
10,000	gj/d	CDN $2.02	AECO	January 1, 2022 - December 31, 2023(2)

Notes:

(1) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 30,000 gj/d on the last trade date of each month for the duration of the contract.
(2) Includes a feature which at the discretion of the counterparty allows for the additional purchase of 10,000 gj/d on the last trade date of each month for the duration of the contract.

Foreign exchange risk

Bonavista is exposed to foreign currency fluctuations as natural gas, natural gas liquids and oil prices are referenced to US dollar denominated prices. Bonavista has mitigated some of this foreign exchange risk by entering into fixed CDN dollar natural gas, natural gas liquids and oil swaps and collars as outlined in the commodity price risk section above. In addition, Bonavista has US dollar denominated senior unsecured notes and interest obligations of which future cash repayments are directly impacted by the CDN dollar to the US dollar exchange rate. To fix the foreign exchange rate on a portion of the US dollar denominated senior unsecured notes, Bonavista has entered into the following contracts to purchase US dollars at predetermined rates on settlement dates that coincide with Bonavista's US dollar debt repayment commitments:

Settlement date	Contract	Notional US$	CDN$/US$
November 2, 2020	US$ purchased forward	$17,800,000	1.3297
November 2, 2022	US$ purchased forward	$5,500,000	1.3318

During the fourth quarter of 2019, Bonavista monetized the value in certain foreign exchange contracts for proceeds of $5.9 million, recorded in "net finance costs" on the consolidated statement of income (loss) and comprehensive income (loss). The transactions monetized in advance of their maturity date included:

Settlement date	Contract	Notional US$	CDN$/US$
November 2, 2020	US$ purchased forward	$142,200,000	1.3018
October 25, 2021	US$ purchased forward	$150,000,000	1.2991
November 2, 2022	US$ purchased forward	$44,500,000	1.2975
May 23, 2023	US$ purchased forward	$40,000,000	1.2974

The fair value recorded on the consolidated statement of financial position for the outstanding financial instrument contracts as at December 31, 2019 was a net liability of $0.7 million (December 31, 2018 - $18.4 million, net asset), of which the net liability of $0.5 million amount relates to financial instrument contracts with term dates within one year (December 31, 2018 - $1.2 million, net asset) and the net liability of $0.1 million relates to financial instrument contracts with term dates beyond one year (December 31, 2018 - $17.2 million, net asset). For the year ended December 31, 2019, an unrealized loss of $19.1 million was recorded on the consolidated statement of income (loss) and comprehensive income (loss) (December 31, 2018 - $37.7 million, unrealized gain).

Bonavista's financial instrument contracts are sensitive to changes in the CDN dollar to the US dollar exchange rate. Holding all other variables constant, a $0.01 change in the forward forecast CDN$/US$ exchange rate at December 31, 2019 would have had an impact of approximately $0.3 million on net loss and comprehensive loss (December 31, 2018 - $3.5 million).

Interest rate risk

Bonavista is exposed to interest rate risk on any amount outstanding on its Canadian bank credit facility. Bonavista manages interest rate risk by having both fixed interest rates on senior unsecured notes and floating interest rates on outstanding bank debt.

Credit risk

Credit risk is the risk of financial loss to Bonavista if a customer or counterparty to a financial instrument fails to meet its contractual obligation and arises, primarily from joint operations partners, oil and natural gas marketers and financial intermediaries. Bonavista's accounts receivable are with oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous oil and natural gas marketers under normal industry sale and payment terms. Bonavista routinely assesses the financial strength of its counterparties. Bonavista may be exposed to certain losses in the event of non-performance by counterparties to financial instrument contracts. Bonavista mitigates this risk by entering into transactions with highly rated financial institutions.

The majority of Bonavista's credit exposure on accounts receivable at December 31, 2019 pertains to accrued sales revenue for December 2019 production volumes. Receivables from oil and natural gas marketers are normally collected by Bonavista on the 25^{th} of the month following production. Receivables with joint operations partners are typically collected within one to three months of the joint operations invoice being issued to the partner. At December 31, 2019 Bonavista's receivables consisted of $47.8 million of receivables from oil and natural gas marketers of which substantially all has been collected subsequent to December 31, 2019 and $11.9 million from joint operations partners of which $3.8 million has been subsequently collected.

Bonavista routinely monitors the age of its receivables, investigating the issue behind past due amounts and reviewing the creditworthiness and collection history of the counterparty. Bonavista considers all amounts greater than 90 days to be past due. At December 31, 2019 Bonavista has $5.1 million in accounts receivable that is considered to be past due (December 31, 2018 - $4.0 million). Although these amounts have been outstanding for greater than 90 days, they are still deemed to be collectible. As the operator of properties, Bonavista does have the ability in most instances to withhold production from joint operations partners, who are in default of amounts owing. The lifetime ECL allowances related to Bonavista's receivables from oil and natural gas marketers and joint operations partners were nominal as at and for the periods ended December 31, 2019 and December 31, 2018.

Liquidity risk

Liquidity risk is the risk that Bonavista will encounter difficulty in meeting obligations associated with its financial liabilities. Bonavista's financial liabilities consist of accounts payable and accrued liabilities, financial instruments contracts, bank debt and senior unsecured notes. Accounts payable consists of invoices payable to trade suppliers for office, field operating activities, and capital expenditures. Bonavista processes invoices within a normal payment period.

Accounts payable and accrued liabilities have contractual maturities of less than one year. Financial instrument contracts have contractual maturities of less than five years on all commodity contracts and range from one to three years on foreign exchange contracts. Bonavista's revolving bank credit facility, as outlined in note 15, "Long-term debt", may at the request of the Corporation with the consent of the lenders, be extended on an annual basis beyond the existing term. Bonavista also has a series of senior unsecured notes outstanding with fixed interest rates, as outlined in note 15, "Long-term debt", which range in maturities from November 2, 2020 to May 23, 2025. Bonavista also has provided for financial convents under both its bank credit facility and senior unsecured notes, the details of which are outlined in note 15, "Long-term debt". Bonavista has forecasted a potential breach of its financial covenants within the next six months on its bank credit facility and senior unsecured notes, and as such is currently in the process of negotiating covenant relief from its lenders, refer to note 2, "Future operations."

Bonavista also maintains and monitors a certain level of adjusted funds flow which is used to partially finance all operating, investing and capital expenditures.

Financial instrument classification and measurement

Bonavista's financial instruments include accounts receivable, financial instrument commodity contracts, financial instrument contracts, accounts payable and accrued liabilities and long-term debt. Bonavista classifies the fair value of these financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instrument.

- Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
- Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.
- Level 3 – Valuation in this level are those with inputs for the asset or liabilities that are not based on observable market data.

Bonavista's financial instrument commodity contracts, financial instrument contracts, bank debt and senior unsecured notes are classified as Level 2 measurements. To estimate the fair value of these financial instruments Bonavista uses quoted market prices when available or fair-value estimates from third party valuation models that use observable market data. Bonavista does not have any recurring fair value measurements classified as Level 1 or Level 3. Bonavista does not have any financial assets or financial liabilities that are subject to offsetting arrangements.

The fair market value recorded on Bonavista's consolidated statement of financial position for financial instrument contracts was:

	December 31, 2019	December 31, 2018
($ thousands)		
Current assets		
Financial instrument commodity contracts(1)	**39,508**	57,192
Financial instrument contracts(1)	**—**	1,200
Long-term assets		
Financial instrument commodity contracts(1)	**14,789**	19,898
Financial instrument contracts(1)	**—**	17,204
Current liabilities		
Financial instrument commodity contracts(1)	**(40,568)**	(2,663)
Financial instrument contracts(1)	**(542)**	—
Long-term liabilities		
Financial instrument commodity contracts(1)	**(26,634)**	(5,226)
Financial instrument contracts(1)	**(138)**	—
Net asset (liability)	**(13,585)**	87,605

(1) Level 2

The fair value of accounts receivable and accounts payable and accrued liabilities approximate their carrying amount due to the short-term nature of those instruments. Borrowings under Bonavista's bank credit facility bear interest at a floating market rate and accordingly the fair market value approximates the carrying value. The fair market value of Bonavista's senior unsecured notes at December 31, 2019 was approximately $744.8 million (December 31, 2018 - $792.1 million), compared to a carrying amount of $753.9 million (December 31, 2018 - $790.7 million).

7. Revenues

Bonavista produces natural gas, natural gas liquids and crude oil from its assets in the Western Canadian Sedimentary Basin ("WCSB"). Bonavista sells its production pursuant to fixed-price or variable-price physical delivery contracts. The transaction price for variable-price contracts is based on a benchmark commodity price, adjusted for quality, location or other factors whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, Bonavista is required to deliver fixed or variable volumes of natural gas, natural gas liquids or crude oil to the contract counterparty.

Production revenue is recognized when Bonavista gives up control of the unit of production at the delivery point agreed to under the terms of the contract. The amount of production revenue recognized is based on the agreed transaction price and the volumes delivered. Any variability in the transaction price relates specifically to Bonavista's efforts to transfer production and therefore the resulting revenue is allocated to the production delivered in the period to which the variability relates. Bonavista does not have any factors considered to be constraining in the recognition of revenue with variable pricing factors. Bonavista’s contracts with customers generally have a term of one year or less, whereby delivery takes place throughout the contract period. Production revenues are normally collected on the business day nearest the 25th day of the month following production.

Bonavista’s production revenues were primarily generated in its Deep Basin and West Central core areas located in Alberta. Bonavista's customers are oil and natural gas marketers and joint operations partners in the oil and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous oil and natural gas marketers under customary industry sale and payment terms.

The following table presents Bonavista's production revenues disaggregated by product:

($ thousands)	**Year ended December 31, 2019**	Year ended December 31, 2018
Production Revenues		
Natural Gas	**190,221**	236,333
Natural Gas Liquids	**140,350**	227,827
Oil	**41,834**	50,807
Total Production Revenues	**372,405**	514,967

($ thousands)	**Year ended December 31, 2019**	Year ended December 31, 2018
Natural Gas Liquids by Component		
Ethane (C_2)	**10,139**	9,227
Propane (C_3)	**21,533**	49,904
Butane (C_4)	**15,100**	49,763
Pentanes plus and condensate (C_{5+})	**93,578**	118,933
Total Natural Gas Liquids	**140,350**	227,827

Under certain marketing arrangements Bonavista will transfer title of its natural gas production to a third party marketing company who will subsequently deliver the natural gas production to an end customer by utilizing Bonavista's pipeline capacity. In such instances Bonavista's pipeline capacity, for the specified contract term, has been assigned to the third party marketing company. This transportation revenue stream is presented within natural gas production revenue which is disaggregated in the below table by type:

($ thousands)	**Year ended December 31, 2019**	Year ended December 31, 2018
Natural Gas Production Revenue	**172,529**	219,243
Transportation Revenue	**17,692**	17,090
Total Natural Gas Production Revenue	**190,221**	236,333

Included in accounts receivable at December 31, 2019 was $47.8 million (December 31, 2018 - $43.5 million) of accrued production revenue related to deliveries for the month ended. There were no significant adjustments for prior period accrued production revenue reflected in the current period. Changes in Bonavista's accrued production revenues result from changes in its production volumes and transaction prices.

8. Capital management

Bonavista's objectives when managing capital are to: (i) preserve financial flexibility which will allow it to execute on its Corporate strategy through expenditures on exploration and development activities; (ii) maintain a strong financial position to support investor, creditor and market confidence; and (iii) deploy capital to provide an appropriate return on investment to its shareholders. Bonavista manages its capital structure and makes adjustments to it in response to changes in economic conditions and the risk characteristics of its underlying natural gas, natural gas liquids and oil assets. This is accomplished by consistently aligning Bonavista's capital programs with adjusted funds flow. Adjusted funds flow is used by management to assess Bonavista's ability to generate the cash flow necessary to finance capital expenditures, expenditures on decommissioning liabilities and meet other 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). The ratio represents the time period it would take to pay off Bonavista's net debt if no further capital expenditures were incurred and if adjusted funds flow remained constant. This ratio is calculated as net debt divided by adjusted funds flow for the most recent calendar quarter, annualized (multiplied by four). This ratio may increase at certain times as a result of acquisitions, low commodity prices and foreign exchange fluctuations. 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 (excluding associated assets and liabilities from financial instrument commodity contracts, lease liabilities and decommissioning liabilities). As at December 31, 2019, Bonavista's ratio of net debt to adjusted funds flow (fourth quarter annualized) was 4.2 to 1 (December 31, 2018 - 3.4 to 1).

To facilitate the management of this ratio, Bonavista prepares annual adjusted funds flow and capital expenditure budgets, which are updated as necessary, and are routinely reviewed and approved by Bonavista's Board of Directors. The Corporation manages its capital structure and makes adjustments by continually monitoring its business conditions, including: the current economic conditions; the risk characteristics of Bonavista's natural gas, natural gas liquids and oil assets; the depth of its investment opportunities; current and forecasted net debt levels; current and forecasted commodity prices; and other factors that influence commodity prices and adjusted funds flow, such as quality and basis differentials, royalties, operating costs and transportation costs.

To maintain or adjust the capital structure, Bonavista considers: its forecasted ratio of net debt to forecasted adjusted funds flow while attempting to finance an acceptable capital expenditure program including acquisition opportunities; the current level of bank credit available from the Corporation's lenders; the availability of other sources of debt with different characteristics than the existing bank debt; the sale of assets; the monetization of financial instrument contracts; issuance of new equity if available on favourable terms; the size of its capital expenditure program; the size of its decommissioning expenditure program and the level of dividends payable to its shareholders. Bonavista shareholders' capital is not subject to external restrictions, however, the Corporation's bank credit facility and senior unsecured notes do contain financial covenants, refer to note 15, "Long-term debt".

The following table provides a reconciliation of cash flow from operating activities to adjusted funds flow:

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
($ thousands)				
Cash flow from operating activities	**47,952**	77,581	**195,736**	291,191
Interest expense(1)	**(9,011)**	(8,553)	**(34,938)**	(35,141)
Decommissioning expenditures(2)	**2,610**	2,198	**9,743**	12,318
Changes in non-cash working capital(3)	**6,151**	(10,151)	**10,431**	(8,773)
Adjusted funds flow(4)	**47,702**	61,075	**180,972**	259,595

Notes:

(1) Interest expense on Bonavista's long-term debt excluding the amortization of debt issuance costs.

(2) The timing of when decommissioning expenditures are incurred is predominately at the discretion of Bonavista's management. However, there is a non-discretionary component that relates to compliance with regulatory requirements and abandonment and reclamation projects where Bonavista is not the operator. For the three months ended December 31, 2019 the non-discretionary component of Bonavista's decommissioning expenditures was $0.9 million (December 31, 2018 - $0.6 million). For the year ended December 31, 2019 the non-discretionary component of Bonavista's decommissioning expenditures was $2.2 million (December 31, 2018 - $3.6 million).

(3) Refer to note 10, "Supplemental cash flow information".

(4) Adjusted funds flow as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities.

The following table provides a reconciliation of long-term debt to net debt and the net debt to adjusted funds flow ratio:

Net Debt to Adjusted Funds Flow	**December 31, 2019**	December 31, 2018
($ thousands)		
Long-term debt	**598,031**	801,625
Working capital(1)	**223,352**	(8,545)
Current assets		
Financial instrument commodity contracts	**39,508**	57,192
Current liabilities		
Financial instrument commodity contracts	**(40,568)**	(2,663)
Lease liabilities(2)	**(3,085)**	—
Decommissioning liabilities	**(8,650)**	(11,704)
Net debt(3)	**808,588**	835,905
Adjusted funds flow (fourth quarter annualized)(3)	**190,808**	244,300
Net debt to adjusted funds flow (fourth quarter annualized) (ratio)(3)	**4.2:1**	3.4:1
Adjusted funds flow(3)	**180,972**	259,595
Net debt to adjusted funds flow (ratio)(3)	**4.5:1**	3.2:1

Notes:

(1) Working capital is equal to current assets less current liabilities as presented on the consolidated statement of financial position. Current assets as at December 31, 2019 were $113.3 million compared to current liabilities of $336.7 million. Current assets as at December 31, 2018 were $127.1 million compared to current liabilities of $118.6 million.

(2) Lease liabilities are included in "accounts payable and accrued liabilities" on the consolidated statement of financial position.

(3) The measure as presented does not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities.

(4) Working capital deficiency as at December 31, 2019 includes $207.7 million of the current portion of long-term debt. There was no long-term debt classified as current in the comparative 2018 period.

As at December 31, 2019, Bonavista had $207.7 million of senior unsecured notes due within the next twelve months which it expects to pay through a combination of adjusted funds flow and its bank credit facility. This expectation may change as a result of Bonavista's ongoing covenant relief process, refer to note 2, "Future operations".

9. Finance costs and income

($ thousands)	**Year ended December 31, 2019**	Year ended December 31, 2018
Finance costs		
Accretion of decommissioning liabilities	**7,389**	8,891
Accretion of other liabilities	**590**	843
Amortization of debt issue costs	**752**	754
Interest on bank debt	**4,357**	4,406
Interest on notes payable	**30,581**	30,735
Interest on lease liabilities	**279**	—
Long-term debt restructuring costs	**2,266**	—
Realized loss on foreign exchange	**472**	—
Unrealized loss on foreign exchange	**—**	60,342
Unrealized loss on financial instrument contracts	**19,084**	—
Total finance costs	**65,770**	105,971
Finance income		
Monetization of financial instrument contracts	**(5,857)**	—
Realized gain on foreign exchange	**—**	(1,822)
Unrealized gain on foreign exchange	**(36,782)**	—
Unrealized gain on financial instrument contracts	**—**	(37,699)
Total finance income	**(42,639)**	(39,521)
Net finance costs	**23,131**	66,450

10. Supplemental cash flow information

($ thousands)	**Year ended December 31, 2019**	Year ended December 31, 2018
Cash provided by (used for):		
Accounts receivable	**(5,042)**	18,740
Prepaid expenses and other assets	**(313)**	586
Accounts payable and accrued liabilities[1]	**(26,516)**	(27,357)
	(31,871)	(8,031)
Related to:		
Operating activities	**(10,431)**	8,773
Investing activities	**(21,440)**	(16,804)
	(31,871)	(8,031)

Note:

(1) Net of interest accrual and current portion of lease liabilities.

11. Property acquisitions

On December 4, 2019, Bonavista completed the acquisition of certain oil and liquids rich natural gas weighted properties within its West Central core area. Given the close proximity of the acquired properties to Bonavista's existing assets, the acquired properties are synergistic to existing operations and complementary to current development plans. The assets were acquired for cash consideration of $55.6 million. In connection with the early adoption of the amendments to IFRS 3, Bonavista applied the optional concentration test to the December 4, 2019 acquisition which resulted in the acquired assets being accounted for as an asset acquisition. As such the purchase price was allocated to the identifiable assets and liabilities based on their relative fair values at the date of acquisition.

The amounts recognized on the date of acquisition to identifiable net assets were as follows:

($ thousands)	**Amount**
Net assets acquired:	
Exploration and evaluation assets	**2,363**
Oil and natural gas properties	**71,361**
Decommissioning liabilities	**(18,150)**
Net assets acquired	**55,574**
Purchase consideration:	
Cash	**55,574**
Total purchase consideration	**55,574**

In the prior year period of 2018, property acquisitions totaled $32.7 million for certain oil and liquids rich natural gas weighted assets located predominately in Bonavista's West Central core area.

12. Property, plant and equipment

Cost	Oil and natural gas properties	Facilities	Other Assets	Right-of-Use Assets	Total
($ thousands)					
Balance as at December 31, 2017	5,145,548	538,005	29,940	—	5,713,493
Additions	149,349	9,311	760	—	159,420
Acquisitions	11,840	14,429	—	—	26,269
Transfers from exploration and evaluation assets	32,064	—	—	—	32,064
Changes in decommissioning liabilities	19,802	—	—	—	19,802
Dispositions	(63,506)	(1,448)	—	—	(64,954)
Balance as at December 31, 2018	5,295,097	560,297	30,700	—	5,886,094
Additions	**123,424**	**9,061**	**1,155**	**6,445**	**140,085**
Acquisitions	**128,326**	**(1,757)**	**—**	**—**	**126,569**
Transfers from exploration and evaluation assets	**14,493**	**—**	**—**	**—**	**14,493**
Changes in decommissioning liabilities	**(118,262)**	**—**	**—**	**—**	**(118,262)**
Dispositions	**(94,136)**	**(24,401)**	**—**	**—**	**(118,537)**
Balance as at December 31, 2019	**5,348,942**	**543,200**	**31,855**	**6,445**	**5,930,442**
Depletion, depreciation, amortization and impairment					
Balance as at December 31, 2017	(2,893,907)	(140,964)	(20,270)	—	(3,055,141)
Depletion, depreciation and amortization	(201,471)	(23,381)	(2,595)	—	(227,447)
Dispositions	29,429	559	—	—	29,988
Balance as at December 31, 2018	(3,065,949)	(163,786)	(22,865)	—	(3,252,600)
Depletion, depreciation, amortization and impairment	**(471,330)**	**(22,298)**	**(2,511)**	**(3,151)**	**(499,290)**
Dispositions	**55,661**	**11,663**	**—**	**—**	**67,324**
Balance as at December 31, 2019	**(3,481,618)**	**(174,421)**	**(25,376)**	**(3,151)**	**(3,684,566)**
Carrying amount					
As at December 31, 2019	**1,867,324**	**368,779**	**6,479**	**3,294**	**2,245,876**
As at December 31, 2018	2,229,148	396,511	7,835	—	2,633,494

For the year ended December 31, 2019, $4.4 million (December 31, 2018 - $5.2 million) of direct general and administrative expenses were capitalized. As at December 31, 2019, future development costs of $1,738.4 million were included in Bonavista's depletion calculation (December 31, 2018 - $1,509.7 million).

As a result of the adoption of IFRS 16 *Leases* on January 1, 2019, a right-of-use asset was recognized in relation to the Corporation's head office lease, equipment rentals and certain vehicles. The cumulative effect of which was an addition of $6.4 million to property, plant and equipment and a depreciation charge of $3.2 million for the year ended December 31, 2019.

During the year ended December 31, 2019, the total consideration received for non-core properties was $21.5 million, resulting in a loss on the sale of property, plant and equipment of $15.3 million and a $1.8 million loss on the sale of exploration and evaluation assets. During the comparative period of 2018, Bonavista disposed of certain non-core properties for total consideration of $26.6 million, resulting in a loss on the sale of property, plant and equipment of $6.7 million and a $0.2 million gain on the sale of exploration and evaluation assets.

Impairment Assessment (2019)

As at December 31, 2019, indicators of impairment were determined to exist in each of Bonavista's CGUs, as a result of a sustained decline in forward commodity benchmark prices for natural gas, natural gas liquids and oil. As such impairment tests were carried out on each of Bonavista's CGUs, the British Columbia CGU, the West Central CGU and the Deep Basin CGU. In the impairment tests conducted on the West Central CGU and Deep Basin CGU the recoverable amounts were determined to exceed the carrying value and as such no impairment charge was recorded at December 31, 2019. However, for the British Columbia CGU it was determined that the carrying value exceeded the recoverable amount and an impairment charge of $14.3 million was recorded at December 31, 2019. As a result of this impairment charge there is no remaining carrying value net of decommissioning liabilities attributable to the British Columbia CGU. Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal.

During the year ended December 31, 2019, Bonavista recorded an impairment charge of $278.0 million, as a result of the impairment tests conducted on each of its CGU's as at September 30, 2019. At September 30, 2019 it was determined that indicators of impairment were present in each of Bonavista's CGUs, as a result of a sustained decline in forward commodity benchmark prices for natural gas, natural gas liquids and oil. Of the $278.0 million impairment charge, $200 million pertained to the West Central CGU, $73 million pertained to the Deep Basin CGU and $5 million pertained to the British Columbia CGU.

The recoverable amount of each CGU tested for impairment at December 31, 2019 was determined using the methodology and assumptions noted below.

- British Columbia CGU, located mainly in northeast British Columbia near Fort St. John, composed of primarily natural gas and natural gas liquids reserves. At December 31, 2019, it was determined that the recoverable value of the British Columbia CGU was nil. The recoverable amount was determined using the fair value less costs of disposal methodology which is designated as Level 3 on the fair value hierarchy.
- West Central CGU, located between Calgary and Drayton Valley, Alberta, composed of primarily natural gas and natural gas liquids reserves. The estimated recoverable amount of the West Central CGU as at December 31, 2019 was calculated to be $1,550.0 million. The recoverable amount was determined using the value in use methodology.
- Deep Basin CGU, located between Edmonton and Fox Creek, Alberta, composed of primarily natural gas reserves. The estimated recoverable amount of the Deep Basin CGU as at December 31, 2019 was calculated to be $685.2 million. The recoverable amount was determined using the value in use methodology.

The proved plus probable reserve values were based on Bonavista's December 31, 2019 reserve report as prepared by its independent reserve engineer GLJ Petroleum Consultants Ltd. The recoverable amount of the CGUs were estimated based on proved plus probable reserve values using before-tax discount rates specific to the underlying composition of reserve categories and risk profile residing in each CGU. The discount rates applied to the different reserve categories ranged from eight to 15 percent when the value in use methodology was used and ten to 20 percent when the fair value less costs of disposal methodology was used. Key input estimates used in the determination of cash flows from Bonavista's oil and gas reserves included: quantities of reserves and future production; forward commodity pricing as prepared by the average of four independent reserve engineer evaluators; development costs; operating costs; royalty obligations; abandonment costs; and discount rates.

Forward Commodity Prices used in the December 31, 2019 Impairment Test(1)

Year	Edmonton Light Crude Oil	WTI Oil	AECO Gas	Foreign Exchange Rate
	(CDN$/bbl)	(US$/bbl)	(CDN$/MMBtu)	(US$/CDN$)
2020	71.58	60.25	2.05	0.7600
2021	75.33	63.11	2.32	0.7675
2022	77.51	66.02	2.60	0.7838
2023	79.77	67.64	2.74	0.7888
2024	81.60	69.16	2.82	0.7888
2025	83.46	70.69	2.91	0.7888
2026	85.34	72.25	2.97	0.7888
2027	87.19	73.77	3.03	0.7888
2028	88.97	75.25	3.10	0.7888
2029	90.79	76.76	3.16	0.7888
Thereafter	2.0%/year	2.0%/year	2.0%/year	0.7888

(1) The average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule and Deloitte Research Evaluation & Advisory price forecasts, effective January 1, 2020.

Forward Commodity Prices used in the September 30, 2019 Impairment Test(1)

Year	Edmonton Light Crude Oil	WTI Oil	AECO Gas	Foreign Exchange Rate
	(CDN$/bbl)	(US$/bbl)	(CDN$/MMBtu)	(US$/CDN$)
2019	68.73	56.31	1.58	0.7536
2020	72.48	60.80	1.87	0.7663
2021	76.06	64.58	2.23	0.7850
2022	78.45	67.60	2.57	0.8000
2023	80.57	69.24	2.74	0.8000
2024	82.57	70.91	2.84	0.8000
2025	84.58	72.59	2.91	0.8000
2026	86.45	74.14	2.97	0.8000
2027	88.20	75.64	3.03	0.8000
2028	90.02	77.16	3.09	0.8000
Thereafter	2.0%/year	2.0%/year	2.0%/year	0.8000

(1) The average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule and Deloitte Research Evaluation & Advisory price forecasts, effective October 1, 2019.

The results of Bonavista's impairment tests are sensitive to changes in any of the key estimates of which changes could decrease or increase the recoverable amounts of assets and result in additional impairment charges or recovery of impairment charges. If the before-tax discount rates used in the determination of the recoverable amounts for Bonavista's British Columbia CGU had decreased by two percent, no impairment charge would have been recorded at December 31, 2019. Similarly, if a before-tax discount rate used in the determination of the recoverable amounts for the Deep Basin CGU and West Central CGU had increased by two percent, Bonavista would have recorded an additional impairment charge of approximately $90.0 million related to its Deep Basin CGU and no impairment in the West Central CGU for the year ended December 31, 2019.

Impairment Assessment (2018)

As at December 31, 2018, indicators of impairment were determined to exist in each of Bonavista's CGUs, as a result of a sustained decline in forward commodity benchmark prices for natural gas. As such impairment tests were carried out on each of Bonavista's CGUs, the British Columbia CGU, the West Central CGU and the Deep Basin CGU. In each impairment test the recoverable amount of the CGU was determined to exceed the carrying value and as such no impairment charge was recorded for the year ended December 31, 2018. Bonavista further determined that there were no sustained changes to factors that led to previously recognized impairment to support a reversal.

The recoverable amount of each CGU tested for impairment at December 31, 2018 was determined using the methodology and assumptions noted below.

- British Columbia CGU, located mainly in northeast British Columbia near Fort St. John, composed of primarily natural gas and natural gas liquids reserves. The estimated recoverable amount of the British Columbia CGU as at December 31, 2018 was calculated to be $22.9 million. The recoverable amount was determined using the fair value less costs of disposal methodology which is designated as Level 3 on the fair value hierarchy.
- West Central CGU, located between Calgary and Drayton Valley, Alberta, composed of primarily natural gas and natural gas liquids reserves. The estimated recoverable amount of the West Central CGU as at December 31, 2018 was calculated to be $1,413.9 million. The recoverable amount was determined using the value in use methodology.
- Deep Basin CGU, located between Edmonton and Fox Creek, Alberta, composed of primarily natural gas reserves. The estimated recoverable amount of the Deep Basin CGU as at December 31, 2018 was calculated to be $960.5 million. The recoverable amount was determined using the value in use methodology.

The proved plus probable reserve values were based on Bonavista's December 31, 2018 reserve report as prepared by its independent reserve engineer GLJ Petroleum Consultants Ltd. The recoverable amount of the CGUs were estimated based on proved plus probable reserve values using before-tax discount rates specific to the underlying composition of reserve categories and risk profile residing in each CGU. The discount rates applied to the different reserve categories ranged from eight to 15 percent when the value in use methodology was used and ten to 20 percent when the fair value less costs of disposal methodology was used. Key input estimates used in the determination of cash flows from Bonavista's oil and gas reserves included: quantities of reserves and future production; forward commodity pricing as prepared by the average of four independent reserve engineer evaluators; development costs; operating costs; royalty obligations; abandonment costs; and discount rates.

Forward Commodity Prices used in the December 31, 2018 Impairment Test(1)

Year	Edmonton Light Crude Oil	WTI Oil	AECO Gas	Foreign Exchange Rate
	(CDN$/bbl)	(US$/bbl)	(CDN$/MMBtu)	(US$/CDN$)
2019	66.93	58.44	1.85	0.7575
2020	74.99	63.75	2.28	0.7763
2021	79.71	67.28	2.68	0.7900
2022	82.91	70.50	2.99	0.8000
2023	86.33	73.55	3.21	0.8050
2024	88.28	75.27	3.37	0.8063
2025	90.35	77.03	3.51	0.8063
2026	92.60	78.90	3.59	0.8063
2027	94.48	80.49	3.68	0.8063
2028	96.41	82.11	3.77	0.8063
Thereafter	2.0%/year	2.0%/year	2.0%/year	0.8063

(1) The average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule and Deloitte Research Evaluation & Advisory price forecasts, effective January 1, 2019.

The results of Bonavista's impairment tests are sensitive to changes in any of the key estimates of which changes could decrease or increase the recoverable amounts of assets and result in impairment charges or in the recovery of previously recorded impairment charges.

13. Exploration and evaluation assets

Carrying amount	
($ thousands)	
Balance as at December 31, 2017	138,231
Additions	8,746
Acquisitions	11,210
Dispositions	(106)
Transfers to property, plant and equipment	(32,064)
Balance as at December 31, 2018	126,017
Additions	**9,391**
Acquisitions	**2,275**
Dispositions	**(1,905)**
Transfers to property, plant and equipment	**(14,493)**
Balance as at December 31, 2019	**121,285**

Impairment Assessment

For the years ending December 31, 2019 and December 31, 2018, Bonavista determined that indicators of impairment existed with respect to its E&E assets largely as a result of changes in future development plans as a result of the decline in forward commodity benchmark prices and as such an impairment test was performed. It was determined that the recoverable amount of Bonavista's E&E assets exceeded the carrying value and, as such, no impairment was recorded in either year.

Further, there was no impairment recorded as a result of the mandatory impairment assessment on the transfer of exploration and evaluation assets to property, plant and equipment during the years ending December 31, 2019 and December 31, 2018.

14. Shareholders' equity

Bonavista is authorized to issue an unlimited number of common shares without nominal or par value, an unlimited number of exchangeable shares without nominal or par value and 10,000,000 preferred shares, issuable in series.

The holders of common shares are entitled to receive dividends as declared by Bonavista and are entitled to one vote per share. Dividends declared during the year ended December 31, 2019 were $0.01 per share (December 31, 2018 - $0.04 per share). On May 2, 2019, Bonavista's Board of Directors suspended the quarterly dividend. The reinstatement of the quarterly dividend program is at the discretion of the Board of Directors.

The exchangeable shares of Bonavista are exchangeable into common shares based on the exchange ratio, which is adjusted quarterly, to reflect dividends paid on common shares. As a result, cash dividends are not paid on exchangeable shares. The holders of exchangeable shares are entitled to one vote multiplied by the exchange ratio for each exchangeable share.

a. Issued and outstanding

Common shares

	Common Shares	Amount
	(thousands)	($ thousands)
Balance as at December 31, 2017	251,747	2,852,643
Issued on conversion of exchangeable shares	196	3,849
Conversion of restricted incentive and performance incentive awards	3,510	—
Share-based compensation	—	14,439
Balance as at December 31, 2018	255,453	2,870,931
Issued on conversion of exchangeable shares	**24**	**454**
Conversion of restricted and performance incentive awards, net of deferred tax	**5,085**	**—**
Share-based compensation	**—**	**10,550**
Balance as at December 31, 2019	**260,562**	**2,881,935**

Exchangeable shares

	Exchangeable Shares	Amount
	(thousands)	($ thousands)
Balance as at December 31, 2017	3,238	93,266
Exchanged for common shares	(133)	(3,849)
Balance as at December 31, 2018	3,105	89,417
Exchanged for common shares	**(16)**	**(454)**
Balance as at December 31, 2019	**3,089**	**88,963**
Exchange ratio as at December 31, 2019	**1.51204**	**—**
Common shares issuable on exchange	**4,671**	**88,963**

b. Share-based compensation

Bonavista's current long-term incentive plans for officers, directors, employees and certain consultants consist of a restricted incentive award ("RIA") plan and a performance incentive award ("PIA") plan. Awards granted under the restricted incentive award plan and performance incentive award plan entitle the holder to receive shares of the Corporation. In 2019, Bonavista adopted a deferred share unit ("DSU") plan primarily for non-management directors and non-executive officers which entitles participants to receive cash, based on the share price of the Corporation's common shares on the payment date.

The number of common shares available for issue under the RIA plan and the PIA plan is limited to 5.4% of Bonavista's issued and outstanding common shares including common shares issuable on the exchange of outstanding exchangeable shares, as approved by shareholders. As at December 31, 2019, the number of shares issuable under Bonavista's long-term incentive plans, in aggregate represented 3.9% of the issued and outstanding common shares including common shares issuable on the conversion of outstanding exchangeable shares.

Share-based compensation expense recognized during the year ended December 31, 2019 was $10.0 million (December 31, 2018 - $10.4 million). For the year ended December 31, 2019, $0.6 million of share-based compensation expense was capitalized to property, plant and equipment (December 31, 2018 - $0.7 million). As at December 31, 2019, the balance of contributed surplus attributable to share-based compensation awards was $52.7 million (December 31, 2018 - $53.2 million).

Stock Option Plan

At December 31, 2019, there were no stock options outstanding. At December 31, 2018 there were 34,000 stock option awards outstanding with a weighted average exercise price of $15.71 per share. Bonavista has discontinued the stock option plan.

Restricted incentive award plan

Bonavista's RIA plan provides compensation to officers, employees and certain consultants based on the notional number of underlying common shares.

Vesting arrangements are within the discretion of the Board of Directors, but unless otherwise determined by the Board of Directors, all awards granted under the RIA plan vest evenly in three tranches, over a period of three years from the date of grant. On the vesting date, the holder will receive, cash or equivalent common shares for each restricted incentive award, including dividends made on the common shares from the date of the grant up to and including the vesting date, net of the statutory withholding tax.

The fair value of restricted incentive awards is determined at the date of grant by using the closing price(2) of Bonavista's common shares. The amount of share-based compensation expense is reduced by an estimated forfeiture rate, which has been estimated to range from one to 12 percent for outstanding restricted incentive awards. The estimated weighted average fair value of restricted incentive awards granted during the year ended December 31, 2019 was $1.14 per award (December 31, 2018 - $1.96 per award). The fair value is recognized as share-based compensation expense over the vesting period with a corresponding increase to contributed surplus. Upon the conversion of the restricted incentive awards, on the predetermined vesting dates, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital.

The following table summarizes the awards outstanding under the RIA plan:

	Restricted Incentive Awards
Balance as at December 31, 2017	3,205,210
Granted	2,664,639
Reinvestment(1)	112,279
Vested	(2,650,006)
Forfeited	(352,555)
Balance as at December 31, 2018	2,979,567
Granted	**4,712,579**
Reinvestment(1)	**90,701**
Vested	**(3,644,864)**
Forfeited	**(241,639)**
Balance as at December 31, 2019	**3,896,344**

Notes:

(1) Reinvestment of dividends earned during the period outstanding.
(2) Weighted average trading price of twenty days preceding the grant date and expected dividends.

Performance incentive award plan

Bonavista's PIA plan provides compensation to officers, certain employees and eligible consultants based on the notional number of underlying common shares.

Awards granted under the PIA plan vest thirty-nine months from the initial date of grant and the number of common shares issued for each award is subject to a performance multiplier ranging from 0 to 2. The payout multiplier is dependent on the performance of Bonavista at the end of the vesting period relative to corporate performance measures determined at the discretion of the Board of Directors. The number of common shares issued for each performance incentive award granted is also adjusted for the payment of dividends from the date of grant to the payment date. On the payment date, Bonavista has sole and absolute discretion to settle the performance incentive awards in the form of either cash or common shares, or some combination thereof, however, it is Bonavista's intention to settle the performance incentive awards in the form of common shares.

The fair value of performance incentive awards is determined at the date of grant by using the closing price(2) of Bonavista's common shares, multiplied by the estimated performance multiplier. For the purposes of share-based compensation a performance multiplier of 1.00 has been assumed for awards granted. Fluctuations in share-based compensation expense may occur due to changes in estimates of performance outcomes. The amount of share-based compensation expense is reduced by an estimated forfeiture rate, which has been estimated to range from three to 14 percent for outstanding performance incentive awards. The estimated weighted average fair value of PIAs granted during the year ended December 31, 2019 was $1.18 per award (December 31, 2018 - $1.96 per award). Upon the conversion of the performance incentive awards, on the predetermined vesting dates, the value in contributed surplus pertaining to the awards is recorded as shareholders' capital.

The following table summarizes the awards outstanding under the PIA plan:

	Performance Incentive Awards
Balance as at December 31, 2017	3,398,972
Granted	1,747,150
Reinvestment(1)	160,993
Vested	(859,676)
Forfeited	(324,734)
Balance as at December 31, 2018	4,122,705
Granted	**3,379,636**
Reinvestment(1)	**466,355**
Vested	**(1,440,151)**
Forfeited	**(127,157)**
Balance as at December 31, 2019	**6,401,388**

Notes:

(1) Reinvestment of dividends earned during the period outstanding and awards earned from the performance multiplier on vesting.
(2) Weighted average trading price of the twenty days preceding the grant date and expected dividends.

Deferred share unit plan

Bonavista's DSU plan provides compensation to non-management directors and non-executive officers. Beginning in 2019, the Corporation's non-management directors are no longer permitted to participate in the RIA and PIA plans but will receive an annual grant of deferred share units and have the option to receive all or a portion of their Board and Committee compensation in the form of deferred share units instead of cash. Each deferred share unit entitles the holder to receive a cash payment equal to the closing price(2) of the equivalent number of common shares of the Corporation. The number of common shares issued for each deferred share unit granted is also adjusted for the payment of dividends from the date of grant to the payment date. Deferred share units vest immediately upon grant and can only be redeemed following the participants departure from the Corporation and must be redeemed prior to December 1st of the year following the departure date.

The following table summarizes the awards outstanding under the DSU plan:

	Deferred Share Units
Balance as at December 31, 2018	—
Granted	**671,864**
Reinvestment[1]	**4,887**
Balance as at December 31, 2019	**676,751**

Notes:

(1) Reinvestment of dividends earned during the period outstanding.

(2) Weighted average trading price of the five days preceding the payment date.

The compensation liability resulting from the cash-settled DSUs granted during the year ended December 31, 2019 was $0.4 million, based on Bonavista's closing share price of $0.61 per share (December 31, 2018 - nil). There were no DSUs cash settled during the year ended December 31, 2019.

c. Per share amounts

The following table summarizes the weighted average common shares and exchangeable shares used in calculating net income (loss) per equivalent share:

	Year ended December 31, 2019	Year ended December 31, 2018
(thousands)		
Common shares	**258,453**	254,087
Exchangeable shares converted at the exchange ratio	**4,694**	4,694
Basic equivalent shares	**263,147**	258,781
Restricted incentive awards	**3,601**	2,881
Performance incentive awards	**5,871**	4,009
Diluted equivalent shares	**272,619**	265,671

15. Long-term debt

	December 31, 2019	December 31, 2018
($ thousands)		
Bank credit facility[1]	**52,559**	11,968
Senior unsecured notes[1][2]	**753,208**	789,657
Total long-term debt	**805,767**	801,625
Current portion of long-term debt	**207,736**	—
Long-term portion of long-term debt	**598,031**	801,625
	805,767	801,625

Notes:

(1) Includes debt issue costs calculated using the effective interest rate method which at December 31, 2019 were $1.4 million (December 31, 2018 - $2.1 million).

(2) Senior unsecured notes consist of CDN$20.0 million and US$565.0 million valued using the exchange rate at December 31, 2019 of $1.2990 CDN to $1.0000 US dollar (December 31, 2018 - $1.3641 CDN to $1.0000 US dollar).

a. Bank credit facility

Bonavista has a $500 million, covenant-based bank credit facility provided by a syndicate of eight domestic banks. There is an accordion feature providing that at any time during the term, on participation of any existing or additional lenders, Bonavista can increase the bank credit facility by $100 million. The current maturity date of the bank credit facility is September 10, 2021. Bonavista also has in place a $50 million demand working capital facility, which is subject to the same covenants as the bank credit facility.

The bank credit facility provides that advances may be made by way of Canadian prime rate loans, bankers' acceptances and/or US dollar LIBOR advances. These advances bear interest at the banks' prime rate and/or at money market rates plus a stamping fee. The total stamping fees range between 50 basis points and 215 basis points on Canadian bank prime and US base rate borrowings and between 150 basis points and 315 basis points on Canadian dollar bankers' acceptance and US dollar LIBOR borrowings. The undrawn portion of the bank credit facility is subject to a standby fee in the range of 30 to 63 basis points. For the year ended December 31, 2019, borrowing costs averaged 4.6% (December 31, 2018 - 4.0%).

At December 31, 2019, Bonavista had $53.2 million drawn (December 31, 2018 - $13.0 million) on its bank credit facility and outstanding letters of credit of $40.0 million (December 31, 2018 - $17.3 million), which reduce the available borrowing capacity on its bank credit facility. All outstanding letters of credit are considered non-financial under the terms of the bank credit facility.

c. Senior unsecured notes issued under a master shelf agreement

Bonavista entered into an uncommitted master shelf agreement that allows for an aggregate draw of up to US$125 million in notes at a rate equal to the related US treasury rate corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. In 2010, Bonavista drew down US$50 million on the master shelf agreement with a coupon rate of 4.86%. Of the US$50 million drawn, US$25 million was repaid on June 4, 2016 and the remaining US$25 million was repaid on June 4, 2017.

Bonavista increased its existing master shelf agreement from US$125 million to US$150 million allowing the Corporation to draw an additional US$100 million in notes at a rate equal to the related US treasury rate corresponding to the term of the notes plus an appropriate credit risk adjustment at the time of issuance. On April 25, 2013, the Corporation drew down US$100 million on the master shelf agreement with a coupon rate of 3.80% and a maturity date of April 25, 2025.

d. Senior unsecured notes not subject to the master shelf agreement

Bonavista issued the following senior unsecured notes by way of a private placement.

Bonavista's senior unsecured notes, including those senior unsecured notes issued under the master shelf agreement, bear fixed interest rates, with a weighted average rate of 4.1% for the years ended December 31, 2019 and 2018. The senior unsecured notes outstanding have maturity dates ranging from November 2, 2020 to May 23, 2025.

The terms and coupon rates of the senior unsecured notes, not subject to the master shelf agreement, are summarized below:

Issued Date	Principal		Coupon Rate	Maturity Dates
November 2, 2010	US	$160.0 million	4.37%	November 2, 2020
November 2, 2010	US	$50.0 million	4.47%	November 2, 2022
October 25, 2011	US	$150.0 million	4.25%	October 25, 2021
April 25, 2013[(1)]	US	$100.0 million	3.80%	April 25, 2025
May 23, 2013	US	$85.0 million	3.68%	May 23, 2023
May 23, 2013	CDN	$20.0 million	4.09%	May 23, 2023
May 23, 2013	US	$20.0 million	3.78%	May 23, 2025

Note:

(1) Subject to an uncommitted master shelf agreement.

e. Debt Covenants

Under the terms of the bank credit facility, Bonavista has provided the covenants that its:

- consolidated senior debt borrowing will not exceed three and one-half times net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment;
- consolidated total debt will not exceed three and one-half times net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment; and
- consolidated senior debt borrowing will not exceed one-half of consolidated total debt plus consolidated shareholders' equity of the Corporation, in all cases calculated based on a rolling prior four quarters.

Further under the terms of the covenants consolidated net income before unrealized gains and losses on financial instrument contracts and marketable securities, interest, taxes and depreciation, depletion, amortization and impairment, as applicable with any acquisition or disposition (the net proceeds of which are greater than $20 million or the Canadian Dollar Exchange Equivalent thereof) made within the applicable period, is to be adjusted as if the acquisition or disposition had been made at the beginning of such period. Furthermore, financial letters of credit are to be included in the determination of consolidated total debt and consolidated senior debt whereas non-financial letters of credit are excluded from such calculations.

Bonavista's consolidated senior debt and consolidated total debt were the same at December 31, 2019 and include Bonavista's senior unsecured notes issued under the master shelf agreement, senior unsecured notes not subject to the master shelf agreement and the bank credit facility. Bonavista's consolidated senior debt may differ from total debt in instances when the Corporation issues senior subordinated debt or enters into a significant capital lease obligation or guarantee. In accordance with the terms of Bonavista's bank credit facility the calculation of senior debt and total debt remained unchanged with the adoption of IFRS 16 *Leases.*

Under the terms of the master shelf agreement and senior unsecured notes, Bonavista has provided similar significant covenants that exist under the bank credit facility.

As at December 31, 2019, Bonavista was in compliance with all covenants under its credit facilities and senior unsecured notes. Total long-term debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment ("EBITDA") and total senior debt to EBITDA was 3.32 times compared to the covenant of less than 3.5 times and total long-term debt to capitalization was 0.41 times compared to the covenant of less than 0.5 times. Management's forecasts for 2020 based upon current strip pricing, indicates a potential breach of its total debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment ("EBITDA") and senior debt to EBITDA as outlined in note 2, "Future operations".

16. Decommissioning liabilities

Bonavista's decommissioning liabilities results from net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. Bonavista estimates the net present value of its total decommissioning liabilities to be $370.6 million at December 31, 2019 (December 31, 2018 - $430.7 million), based on an estimated total future undiscounted and uninflated liability of approximately $418.5 million (December 31, 2018 - $471.8 million). A risk-free rate of approximately 1.76% (December 31, 2018 - 2.18%) based on the Bank of Canada's long-term risk-free bond rate and an inflation rate of 1.35% (December 31, 2018 - 1.80%) were used to calculate the present value of the decommissioning liability as at December 31, 2019.

During 2019, Bonavista revised certain aspects of its decommissioning liability estimates by reviewing all associated cost estimates at an individual well and facility level. These cost estimates further consider specific well characteristics including but not limited to well type, well vintage, well depth, any site-specific costs and area-based abandonment programs. Bonavista has also incorporated provincial regulatory requirements in when it expects expenditures will be settled. At December 31, 2019 Bonavista estimates expenditures required to settle the liability will be made over the next 72 years with the majority of payments being made in years 2025 to 2055.

The following table reconciles Bonavista's provision for its decommissioning liabilities:

($ thousands)	**Year ended December 31, 2019**	Year ended December 31, 2018
Balance, beginning of year	430,746	409,326
Accretion expense	**7,389**	8,891
Liabilities incurred	**1,746**	2,219
Liabilities acquired	**18,150**	4,825
Liabilities disposed	**(14,757)**	(1,999)
Liabilities settled	**(9,743)**	(12,318)
Change in estimate(1)(2)	**(62,963)**	19,802
Balance, end of year	**370,568**	430,746
Expected to be incurred within one year	**8,650**	11,704
Expected to be incurred beyond one year	**361,918**	419,042

Notes:

(1) Relates to the revaluation of acquired decommissioning liabilities using a risk-free discount rate. At the date of acquisition, the acquired decommissioning liabilities were recorded at fair value.

(2) Relates to changes in estimated costs, discount rates and anticipated settlement dates of decommissioning liabilities.

17. Lease liabilities

($ thousands)	
Balance as at January 1, 2019	**8,926**
Interest expense	**279**
Lease payments	**(5,178)**
Balance as at December 31, 2019	**4,027**
Current portion of lease liabilities[1]	**3,085**
Long-term portion of lease liabilities[2]	**942**

Notes:

(1) Recorded in "accounts payable and accrued liabilities" on the consolidated statement of financial position.
(2) Recorded in "other long-term liabilities" on the consolidated statement of financial position.

The following table is a summary of the undiscounted cash outflows relating to Bonavista's lease liabilities:

	As at December 31, 2019
($ thousands)	
Less than 1 year	3,219
Years 2 and 3	830
Years 4 and 5	268
Thereafter	—
Total[1]	4,317

Note:

(1) Includes both interest expense and lease payments.

Bonavista has lease liabilities for contracts related to its Calgary head office space, field equipment and certain vehicles. Discount rates during the year ended December 31, 2019 averaged 4.3% in the determination of the lease liabilities, depending on the duration of the lease term.

On July 25, 2019, Bonavista entered into a new four-and-a-half year lease for its Calgary head office space commencing on August 1, 2020. The estimated right-of-use asset and lease liability that will be recognized when Bonavista assumes possession of the new office space is $4.8 million.

18. Deferred income taxes

The provision for income tax differs from the result which would have been obtained by applying the combined Federal and Provincial income tax rates to income before taxes. The difference results from the following items:

($ thousands)	**Year ended December 31, 2019**	Year ended December 31, 2018
Income (loss) before taxes	**(413,008)**	26,914
Current statutory income tax rate[1]	**26.5%**	27.0%
Income tax expense (recovery) at current statutory rate	**(109,447)**	7,267
Unrecognized deferred tax asset	**73,935**	5,616
Non-deductible share-based compensation	**2,199**	2,390
Effect of tax rate changes and rate variance	**10,691**	—
Other	**(389)**	(174)
Deferred income taxes	**(23,011)**	15,099

(1) The tax rate consists of the combined federal and provincial statutory tax rates for Bonavista for the years ended December 31, 2018 and December 31, 2019.

On May 28, 2019 the Alberta government tabled legislation to decrease the general corporate tax rate to 11% from 12% on July 1, 2019, with further one percent rate reductions every year on January 1 until the general corporate tax rate is eight percent on January 1, 2022. As these corporate income tax measures were included in Alberta Bill 3 they were considered substantively enacted under IFRS in the second quarter of 2019. As a result of the reduction in the corporate provincial tax rate, Bonavista analyzed the expected timing of settlement of the taxable temporary differences which give rise to deferred income tax assets and liabilities and re-measured these amounts using the appropriate, newly enacted corporate provincial income tax rates. This rate reduction resulted in an approximately $10.7 million reduction in Bonavista's deferred income tax asset at December 31, 2019.

($ thousands)	**Year ended December 31, 2019**	Year ended December 31, 2018
Deferred income tax liabilities:		
Foreign exchange on long-term debt	**206,688**	345,354
Financial instrument contracts	**—**	18,662
Debt issue costs	**306**	543
Deferred income tax assets:		
Decommissioning liabilities	**(85,750)**	(116,172)
Non-capital losses	**(120,681)**	(220,620)
Other liability	**—**	(2,986)
Share-based compensation	**(563)**	(1,099)
Issue costs	**—**	(671)
Deferred income tax liability	**—**	23,011

Deferred income tax expense (recovery) in a non-cash item relating to temporary differences between the accounting and tax basis of Bonavista's assets and liabilities. As at December 31, 2019, Bonavista unrecognized a deferred tax asset of $73.9 million in respect of deductible temporary differences. The material uncertainty related to the outcome of Bonavista's process of negotiating covenant relief, refer to note 2, "Future operations", was considered to affect the assessment of the probability that future taxable income will be available against which the Corporation can utilize the benefits of tax pools in excess of the carrying amount of assets. As at December 31, 2019, Bonavista had approximately $2,319.8 million of estimated tax pools available for deduction against future income.

The following is a summary of Bonavista's estimated tax pools:

($ thousands)	**December 31, 2019**	December 31, 2018
Canadian oil and gas property expense	**428,236**	435,744
Canadian development expense	**489,785**	447,826
Canadian exploration expense	**377,419**	369,612
Undepreciated capital cost	**195,817**	218,970
Non-capital losses	**819,307**	818,029
Other	**9,243**	6,954
Total	**2,319,807**	2,297,135

Non-capital losses carry forward of $819.3 million (December 31, 2018 - $818.0 million) expire in the years 2028 through 2039. Bonavista has capital losses of $30.7 million (December 31, 2018 - $36.1 million) available for carry forward against future capital gains indefinitely that are not included in the unrecognized deferred income tax asset. For the years ended December 31, 2019 and 2018 Bonavista paid no tax installments.

19. Contractual obligations and commitments

The following table is a summary of Bonavista's contractual obligations and commitments at December 31, 2019:

($ thousands)	Total	2020	2021	2022	2023	2024 and thereafter
Long-term debt repayments(1)(3)(4)	805,767	207,736	247,201	64,858	130,202	155,770
Interest payments(2)(3)	78,768	29,578	20,489	13,068	7,844	7,789
Transportation expenses(5)	135,547	31,709	27,889	25,261	9,511	41,177
Total contractual obligations	**1,020,082**	**269,023**	**295,579**	**103,187**	**147,557**	**204,736**

Notes:

(1) Long-term debt repayments include the principal payments due on senior unsecured notes. Based on the existing terms of the revolving bank credit facility, the amounts owing under this facility are required to be paid on September 10, 2021.

(2) Fixed interest payments on senior unsecured notes.

(3) US dollar payments are converted using the exchange rate at December 31, 2019 of $1.2990 CDN to $1.0000 US dollar.

(4) With respect to the long-term debt repayment obligations Bonavista has entered into financial instrument contracts to reduce its exposure to the CDN dollar to the US dollar exchange rate associated with the future cash repayments of its US denominated senior unsecured notes. The underlying notional amount of the financial instrument contracts maturing on the maturity dates of Bonavista US denominated senior unsecured notes is US$23.3 million at an average CDN$/US$ rate of $1.3302.

(5) Includes a Long Term Fixed Price (LTFP) contract with TransCanada that commenced November 1, 2017. This 10-year contract contains an early termination policy after 5 years which has been assumed to be exercised in the contractual obligation above.

20. Supplemental disclosure

a. Income statement presentation

Bonavista's statement of income (loss) and comprehensive income (loss) is prepared primarily according to the nature of expense, with the exception of employee compensation costs which are included in both operating and general and administrative expenses.

The following table details the amount of total employee compensation costs included in the operating and general and administrative expenses:

	Year ended December 31, 2019	Year ended December 31, 2018
($ thousands)		
Operating	**7,576**	8,198
General and administrative	**20,417**	21,792
Total employee compensation costs	**27,993**	29,990

For the year ended December 31, 2019, $2.2 million (December 31, 2018 - $3.0 million) of employee compensation costs were capitalized.

b. Compensation of key management personnel

Bonavista has determined that its key management personnel includes both officers and directors. Short-term benefits are comprised of salaries and directors fees, annual bonuses and other benefits. In addition, share-based compensation provided to key management personnel includes awards offered under Bonavista's long-term incentive plans.

The following table details remuneration to key management personnel included in general and administrative expenses:

	Year ended December 31, 2019	Year ended December 31, 2018
($ thousands)		
Short-term benefits	**3,075**	3,356
Share-based payments(1)	**4,677**	3,068
	7,752	6,424

Note:

(1) Share-based payments represent the fair value of restricted incentive awards, performance incentive awards and deferred share units granted during the period.

c. Reconciliation of financing liabilities arising from financing activities

The following table provides a detailed breakdown of the cash and non-cash changes in financing liabilities arising from financing activities:

	Year ended December 31, 2018	**Cash flows**	**Amortization of debt issue costs**	**Unrealized foreign exchange gain**	**Year ended December 31, 2019**
($ thousands)					
Bank credit facility	11,968	**40,172**	**419**	**—**	**52,559**
Senior unsecured notes	789,657	**—**	**333**	**(36,782)**	**753,208**
Total financial liabilities from financing activities	801,625	**40,172**	**752**	**(36,782)**	**805,767**

CORPORATE INFORMATION

DIRECTORS

Keith A. MacPhail, (2)(4)
Chair

Jason E. Skehar, (4)
President and Chief Executive Officer

Ian S. Brown (1)(3)

David P. Carey (2)(3)(4)

George S. Armoyan (4)

Mary Hemmingsen(1)

Theresa B.Y. Jang (1)(3)

Robert G. Phillips (3)

Ronald J. Poelzer (1)(4)

Christopher P. Slubicki (2)(4)

(1) Member of the Audit Committee

(2) Member of the Reserves Committee

(3) Member of the Governance and Compensation Committee

(4) Member of the Executive Committee

OFFICERS

Jason E. Skehar,
President and Chief Executive Officer

Bruce W. Jensen,
Chief Operating Officer

Dean M. Kobelka,
Vice President, Finance and Chief Financial Officer

Rochelle L. Estep,
Vice President, Strategy and Planning

Colin J. Ranger,
Vice President, Operations

Lynda J. Robinson,
Vice President, Human Resources and Administration

Scott W. Shimek,
Vice President, Resource Development

Grant A. Zawalsky,
Corporate Secretary

AUDITORS

KPMG LLP
Chartered Professional Accountants
Calgary, Alberta

BANKERS

Canadian Imperial Bank of Commerce
The Toronto-Dominion Bank
Bank of Montreal
Royal Bank of Canada
The Bank of Nova Scotia
National Bank of Canada
Alberta Treasury Branches
Caisse Centrale Desjardins
Calgary, Alberta

ENGINEERING CONSULTANTS

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company
Calgary, Alberta

STOCK EXCHANGE LISTING

Toronto Stock Exchange
Trading Symbol “BNP”

HEAD OFFICE

1500, 525 – 8th Avenue SW
Calgary, Alberta T2P 1G1
Telephone: (403) 213-4300
Facsimile: (403) 262-5184
Email: investor.relations@bonavistaenergy.com
Website: www.bonavistaenergy.com

FOR FURTHER INFORMATION CONTACT:

Jason E. Skehar
President and CEO

or

Dean M. Kobelka
Vice President, Finance and CFO

BONAVISTA ENERGY CORPORATION