Pipestone Energy Corp. – Financial and Operating Highlights

($ thousands, except per unit and per share amounts)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
Financial				
Sales of liquids and natural gas	**$ 48,796**	$ 59	**$ 62,521**	$ 1,628
Cash from (used in) operating activities	**30,750**	(3,490)	**10,562**	(3,868)
Adjusted funds flow from (used in) operations [1]	**16,608**	(8,260)	**2,788**	(8,160)
Per share, basic and diluted [2]	**0.09**	(0.14)	**0.01**	(0.15)
Loss	**(13,143)**	(9,603)	**(13,985)**	(12,122)
Per share, basic and diluted [2]	**(0.07)**	(0.16)	**(0.07)**	(0.22)
Gross capital expenditures	**36,457**	60,252	**162,194**	109,264
Net acquisitions	**$ -**	$ -	**214**	1,098
Working capital (deficit) *(end of period)*			**(12,015)**	(21,728)
Bank debt *(end of period)*			**163,048**	53,436
Shareholders' equity *(end of period)*			**370,075**	114,058
Available funding (deficit) *(end of period)* [3]			**$ 41,891**	$ (13,952)
Cash return on invested capital (CROIC) *(%)* [3]	**13.4%**	NMN [7]	**NMN [7]**	NMN [7]
Return on capital employed (ROCE) *(%)* [3]	**5.0%**	NMN [7]	**NMN [7]**	NMN [7]
Shares outstanding *(end of period)* [2]			**189,783**	75,568
Weighted-average basic shares outstanding [2]	**189,743**	60,707	**188,401**	54,780
Weighted-average diluted shares outstanding [2]	**189,777**	60,707	**188,419**	54,780
Operations				
Production				
Crude oil *(bbls/d)*	**60**	-	**52**	-
Condensate *(bbls/d)*	**5,284**	73	**1,744**	91
Other Natural Gas Liquids (NGL) *(bbls/d)*	**1,110**	-	**341**	-
Total NGL *(bbls/d)*	**6,394**	73	**2,085**	91
Natural gas *(Mcf/d)*	**50,588**	-	**15,751**	-
Total *(boe/d)* [4]	**14,885**	73	**4,762**	91
Condensate and crude oil *(% of total production)*	**36%**	100%	**38%**	100%
Total liquids *(% of total production)*	**43%**	100%	**45%**	100%
Benchmark prices				
Crude oil – WTI *(C$/bbl)*	**$ 75.16**	$ 77.75	**$ 75.66**	$ 83.94
Condensate – Edmonton Condensate *(C$/bbl)*	**74.95**	60.32	**71.40**	78.78
Natural gas – AECO 5A *(C$/GJ)*	**2.35**	1.57	**1.70**	1.52
Average realized prices [5]				
Crude oil *(per bbl)*	**62.17**	-	**66.91**	-
Condensate *(per bbl)*	**71.20**	8.60	**70.01**	49.11
Other NGL *(per bbl)*	**13.38**	-	**14.42**	-
Total NGL *(per bbl)*	**61.15**	8.60	**60.89**	49.11
Natural gas *(per Mcf)*	**2.68**	-	**2.59**	-
Crude oil *(per bbl)*	**62.17**	-	**66.91**	-
Netbacks				
Revenue *(per boe)*	**35.63**	8.60	**35.97**	49.11
Royalties *(per boe)*	**(1.60)**	(3.96)	**(1.68)**	(4.14)
Operating expenses *(per boe)*	**(13.51)**	(11.57)	**(13.89)**	(10.16)
Transportation *(per boe)*	**(3.26)**	-	**(4.12)**	-
Operating netback *(per boe)* [3]	**17.26**	(6.93)	**16.28**	34.81
Funds flow netback *(per boe)* [3]	**$ 12.13**	$ (1,221.29)	**$ 1.60**	$ (246.23)

(1) See "Additional subtotal – Adjusted funds flow from operations" under "Critical Accounting Judgments, Estimates and Policies".

(2) The number of common shares has been adjusted retrospectively to reflect the 10:1 share consolidation, as well as the 0.5996 exchange ratio, as part of the Corporate Acquisition.

(3) See “Non-GAAP measures”.

(4) For a description of the boe conversion ratio, see “Basis of Barrel of Oil Equivalent”. References to crude oil in production amounts are to the product type “tight oil” and references to natural gas in production amounts are to the product type “shale gas”.

(5) Figures calculated before hedging.

(6) IFRS 16, *Leases*, was adopted on January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See “Critical Accounting Judgments, Estimates and Policies”.

(7) NMN – not meaningful number at this time as Pipestone Energy had minimal production throughout the majority of 2019.

Management’s Discussion and Analysis

This management’s discussion and analysis (MD&A) of operating and financial results of Pipestone Energy Corp. (“Pipestone Energy” or the “Company”) is dated March 17, 2020 and is based on currently available information. It should be read in conjunction with the audited financial statements and accompanying notes for the years ended December 31, 2019 and 2018. Unless otherwise noted, all financial information is presented in thousands of Canadian dollars and is in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), interpretations of the International Financial Reporting Interpretations Committee (IFRIC), and with Canadian generally accepted accounting principles (GAAP). These documents, along with other statutory filings, are available on SEDAR at www.sedar.com and on the Company’s website at www.pipestonecorp.com.

Refer to the end of the MD&A for commonly used abbreviations.

Readers should read “Forward-Looking Statements” at the end of the MD&A, which explains the basis for and limitations of statements throughout this report that are not historical facts and may be considered “forward-looking statements” under securities regulations.

Additional risks, uncertainties and other factors are discussed in Pipestone Energy’s annual information form dated March 17, 2020, a copy of which is available electronically on SEDAR at www.sedar.com.

Description of Pipestone Energy

Pipestone Energy is engaged in the exploration for, and development and production of, oil and natural gas liquids (including condensate, butane and propane) herein collectively referenced as “liquids” as well as natural gas in Western Canada. The Company’s head office is located in Calgary, Alberta. The Company is focused on developing its liquids-rich assets in the Pipestone area of the Alberta Montney trend. Pipestone Energy is committed to building long term value for its shareholders and values the partnerships that it is developing within its operating community. Pipestone Energy trades on the TSX Venture Exchange under the symbol PIPE.

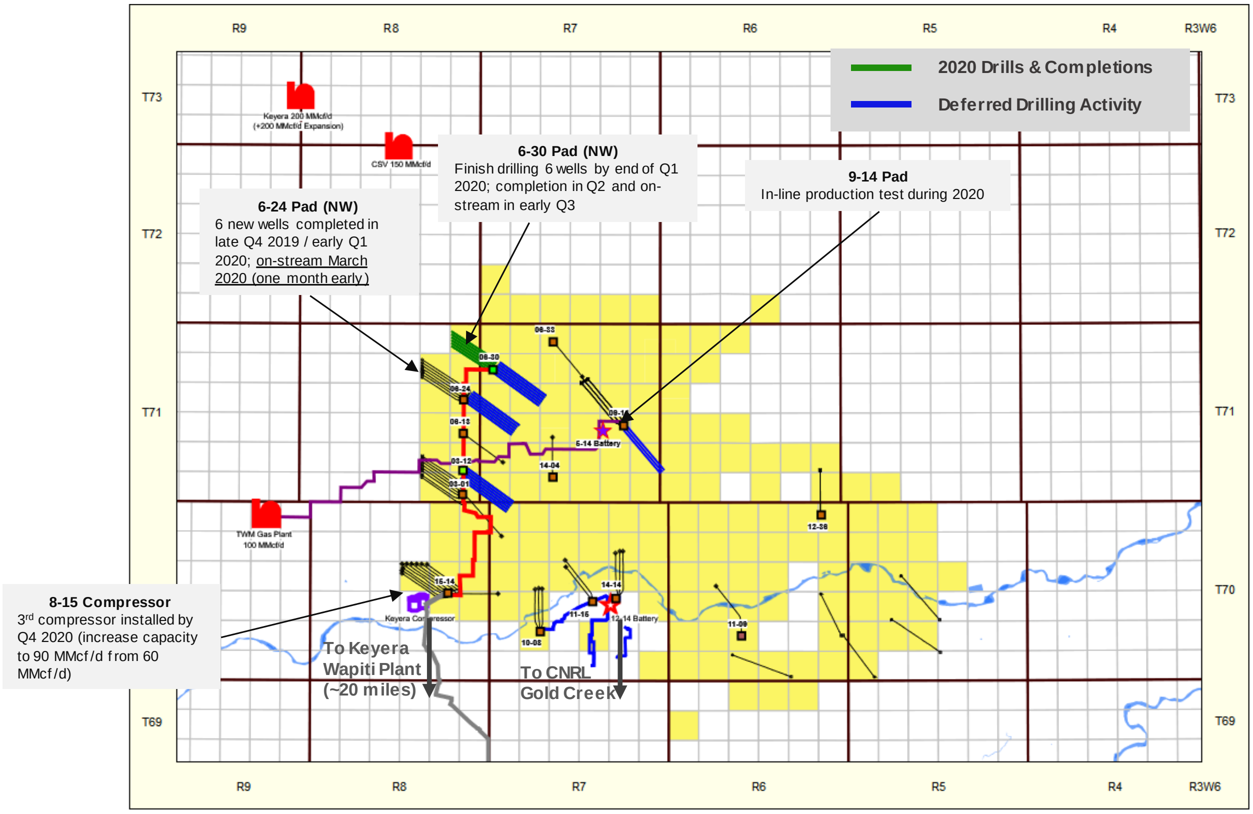
On January 4, 2019 the Company completed its reverse takeover of, and amalgamation with, Blackbird Energy Inc. (the “Corporate Acquisition”). Prior to the Corporate Acquisition, Pipestone Energy was a privately held entity, operating under the name Pipestone Oil Corp. (“Predecessor Pipestone”), incorporated under the Business Corporations Act (Alberta) and a wholly-owned subsidiary of Canadian Non-Operated Resources LP (“CNOR LP”), a privately held partnership formed under the laws of Alberta. The comparative figures presented for 2018 are that of Predecessor Pipestone.

Pipestone Energy is early in its development lifecycle. As of December 31, 2019, Pipestone Energy has accumulated over 140 net Montney sections (89,600 net acres) and has a total of 28 wells on production, 8 of which are legacy wells acquired in the Corporate Acquisition and 20 are new wells brought on in the last four months of 2019 North of the Wapiti River.

The Company has completed building an in-field gathering system to interconnect with third-party processing infrastructure and egress capacity. In mid-September 2019, tie-ins were completed to both the Tidewater Pipestone Plant and the Keyera Wapiti Plant allowing Pipestone Energy to begin producing wells located North of the Wapiti River at the 15-14 and 03-01 pad-sites, and from one well at the 06-24 pad-site. The initiation of production from these wells was approximately one-month ahead of the originally planned schedule. Production continued to ramp-up in Q4 2019 as the third-party infrastructure start-up issues were worked through and run times improved. Pipestone Energy has also secured the firm transportation required to match its near-term forecasted liquids and natural gas production.

Guidance, Development Plan and Outlook for 2020

2020 Capital Program and Operations Update



In response to the dramatic decline in crude oil pricing, as a result of the COVID-19 virus' negative impact on global demand and the failure of OPEC and Russia to reach an agreement of production cuts, Pipestone Energy is proactively protecting its balance sheet by reducing its forecasted annual capital spending program from $145 - $155 million to $55 - $65 million. The capital reduction results in a modest change to Pipestone Energy's 2020 previous production guidance from 18,000 – 20,000 boe/d to 17,000 – 18,000 boe/d. Exit production guidance is also being reduced from 20,000 – 22,000 boe/d to 16,000 – 17,000 boe/d as a direct result of the deferral of one pad (6 wells) not being brought on production this year. At a revised forecast price deck of US$40 per barrel WTI and C$1.75 per GJ AECO, the Company expects to generate corporate cash flow of $55 - $65 million. Through a combination of swaps and collars, the Company has ~3,200 bbl/d of CAD denominated WTI oil hedged at ~C$79 per barrel during H1 2020, which represent more than 60% of its forecast after-royalties condensate production for that period.

The focus of Pipestone Energy's development in 2020 is concentrated in areas with the highest projected condensate content and deliverability. During 2020, the Company will bring 12 new wells on production from 2 pads. The first pad at 6-24 was completed in December 2019, with some carry-over expenditures into Q1 2020 and brought on initial production earlier this month. The final well of six is currently being drilled on the 6-30 pad, with completion operations scheduled for Q2 2020 and projected on-stream timing of Q3 2020. Once drilling has finished on the 6-30 pad, the Company plans to suspend drilling operations. In 2020, Pipestone Energy is deferring approximately $70 million in drilling & completion related capital, approximately $15 - 18 million of infrastructure and miscellaneous capital and expects to realize between $2 to 3 million in aggregate cost savings on DCE&T capital incurred due to expected efficiencies.

Pipestone Energy's previous 2020 Capital Guidance was predicated on a single drilling rig being utilized continuously for the full year. To the extent oil prices recover in H2 2020, the Company has the optionality to resume drilling operations and accelerate its development trajectory by utilizing two rigs per pad and deploying two frac crews for completions as Pipestone Energy did successfully in December 2019. Utilizing two drilling rigs and two completion crews per pad significantly shortens cycle times, allowing for a timely response to improving market conditions. Preservation of Pipestone Energy's strong balance sheet is paramount to our go forward strategy and we will continue to allocate capital to those projects that yield the highest possible returns.

2020 Outlook

In response to the current commodity price weakness which has been exacerbated by threats of the spread of the COVID-19 virus slowing the world economy and OPEC and Russia's failure to reach agreement on production cuts, Pipestone Energy has decided to significantly reduce its 2020 capital spending program. Despite this, Pipestone Energy is well positioned to deliver a combination of year-over-year production growth and generate top-decile returns on capital employed, while maintaining a solid balance sheet with sufficient available liquidity. This year's development expenditures are concentrated around what are the most condensate-rich results realized to date by the Company and will be weighted approximately 85% to half-cycle DCE&T expenditures. The 2020 capital program will still deliver substantial year-over-year production growth of 20% from Q4 2019 to Q4 2020, despite the substantial pullback in the capital program.

Fourth Quarter 2019 Corporate Highlights

- Production for the three months and year ended December 31, 2019 was 14,885 boe/d (comprised of 36% condensate and 43% total liquids) and 4,762 boe/d (comprised of 37% condensate and 45% total liquids), respectively, despite third-party processing facility challenges experienced through-out the quarter. The Company successfully exceeded its 2019 exit guidance of 14,000 – 16,000 boe/d with ~17,000 boe/d average production in December;

- In December 2019, Pipestone Energy successfully refinanced its $198.5 million first lien term-debt facilities with a more cost effective and flexible $225 million Reserve Based Loan ("RBL"), consisting of a $195 million syndicated revolving facility and a $30 million bilateral operating facility. The RBL provides sufficient liquidity for the Company to operate its business plan. In addition, the revolving facility provides for a $25 million increase to the borrowing capacity, subject to mutual consent of the lenders. The RBL matures on November 30, 2020, with a one-year term-out period if it is not extended. The borrowing base will be re-determined biannually, in the spring and fall each year.

- In Q4 2019, drilling operations were successfully finished at the 06-24 pad-site with the remaining four wells drilled of the six well program. The 06-24 wells had an average lateral length of 2,600 metres and an average drilling cost of $2.2 million per well. The completion of these wells was accelerated into December 2019 and the wells were brought on-stream in March 2020. The drilling rig was moved to the 06-30 pad in Q4 2019 and drilled six surface hole locations prior to year-end, Pipestone Energy exited 2019 with all of its planned capital projects completed on-time and under-budget. The Company realized significant cost savings on its 2019 capital program, allowing it to accelerate the 06-24 completions into 2019 within its capital guidance. Net capital spend in 2019, including acquisitions and net of dispositions, was $148.4 million.

Capital Expenditures

($ thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
	$	$	**$**	$
Drilling	**12,143**	8,814	**26,118**	28,419
Completions	**20,940**	24,417	**58,571**	46,790
Production equipment and facilities	**729**	26,617	**67,579**	28,826
Land and other	**1,889**	404	**6,561**	5,229
Capitalized G&A	**756**	-	**3,365**	-
Gross capital expenditures, per cash flow statement	**36,457**	60,252	**162,194**	109,264
Acquisitions	**-**	-	**214**	1,098
Proceeds on asset under construction	**-**	-	**(13,967)**	-
Net capital expenditures	**36,457**	60,252	**148,441**	110,362
Exploration and evaluation from Corporate Acquisition	**-**	-	**36,942**	-
Property and equipment from Corporate Acquisition	**-**	-	**197,755**	-
	36,457	60,252	**383,138**	110,362
Right-of-use lease assets from Corporate Acquisition	**-**	-	**1,630**	-
Right-of-use lease additions	**51,590**	-	**53,082**	-
	88,047	60,252	**437,850**	110,362

2019 was a transformational year for Pipestone Energy as it has built out significant infield infrastructure which is now connected to third-party processing and existing egress which will support production growth up to our current infrastructure capacity of approximately 33,000 boe per day. The Company has continued to drill and complete wells North of the Wapiti River with the initial production from its 15-14 and 03-01 pad-site wells commencing in mid-September 2019. The 2019 capital program was ambitious and represented a significant investment which allowed the Company to realize commercial production to exit the year.

At December 31, 2019, the Company had exploration and evaluation assets of $38.9 million (December 31, 2018 – $6.7 million). This included approximately 89 net Montney sections (56,960 net acres) of undeveloped land.

At December 31, 2019, the Company had property and equipment of $518.2 million. This included developed land and costs associated with the wells the Company has drilled and acquired to date. As well, it included $0.6 million incurred since inception to purchase computer hardware and software, associated office furniture and office improvements for use by Pipestone Energy employees and consultants to evaluate exploitation opportunities. Additionally, under IFRS 16, *Leases*, Pipestone Energy recognized $53.2 million of right-of-use (“ROU”) assets relating to office space, field equipment and compressor leases at December 31, 2019.

During the three months ended December 31, 2019, Pipestone Energy invested a total of $36.5 million compared to $60.3 million in the three months ended December 31, 2018. The decrease was primarily due to reduced spending on production equipment and facilities as the Company completed its in-field gathering system build out prior to Q4 2019.

For the three-month period ended December 31, 2019, Pipestone Energy successfully executed and accelerated its Montney-focused development program by:

- Drilling and rig releasing 4 wells (4 net) from the 06-24 pad-site;
- Finalizing the construction of its 06-30 pad-site and drilling 6 surface hole locations (all 6 of these wells are expected to be rig-released and recognized in Q1 2020); and
- Completing 6 wells (6 net) from the 06-24 pad-site (fracs were pumped and recognized in Q4 2019 with approximately 20 percent of the remaining completion capital incurred subsequently in Q1 2020). As noted above these wells were brought on production in early March 2020.

During the year ended December 31, 2019, Pipestone Energy invested a total of $162.2 million of gross capital ($148.4 million of net capital) compared to $109.3 million in the year ended December 31, 2018. The increase was due to significant spending on production equipment and facilities as the Company completed its in-field gathering system build out in 2019 and also completed a greater number of wells (16 in 2019 vs 9 in 2018), partially offset by realized cost savings on its completion program in 2019.

Pipestone Energy exited 2019 with all of its planned projects completed on-time and under-budget. As a result, the Company realized significant cost savings on its 2019 capital program, allowing it to accelerate the 06-24 completions into 2019 within its capital guidance. Capital spend in 2019, including acquisitions and net of dispositions, was $148.4 million.

Drilling and Completion Activity

	Three months ended December 31,		Year ended December 31,	
Montney well activity (1)	**2019**	2018 (2)	**2019**	2018 (2)
Gross & Net				
Wells drilled (rig-released)	**4.0**	3.0	**10.0**	9.0
Wells completed	**6.0**	6.0	**16.0**	9.0

(1) Well counts include all horizontal Montney wells and exclude surface holes, water injection wells, and wells that were re-drilled or abandoned. Drilling counts are based on rig release date.

(2) The comparative figures presented for 2018 are that of the predecessor company, Pipestone Oil Corp.

Financial and Operating Results

Production

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
Daily average volume				
Crude oil *(bbls/d)*	**60**	-	**52**	-
Condensate *(bbls/d)*	**5,284**	73	**1,744**	91
Other NGL *(bbls/d)*	**1,110**	-	**341**	-
Total NGL *(bbls/d)*	**6,394**	73	**2,085**	91
Natural gas *(Mcf/d)*	**50,588**	-	**15,751**	-
Total sales *(boe/d)*(1)	**14,885**	73	**4,762**	91
Production weighting				
Crude oil	**0%**	0%	**1%**	0%
Condensate	**36%**	100%	**37%**	100%
Other NGL	**7%**	0%	**7%**	0%
Total NGL	**43%**	100%	**44%**	100%
Natural gas	**57%**	0%	**55%**	0%
	100%	100%	**100%**	100%

(1) References to crude oil in production amounts are to the product type “tight oil” and references to natural gas in production amounts are to the product type “shale gas”.

Starting in mid-September, Pipestone Energy began bringing on production from North of the Wapiti River at its 15-14 and 03-01 pad-sites. While the three months ended December 31, 2019 represented the first full quarter of production for the Company, these production volumes were restricted due to both startup and runtime challenges associated with third-party facilities. The Company anticipates that the performance of its third-party processing facilities will improve over the course of 2020 as it continues to ramp-up production volumes delivered through the systems.

Production for the three months ended December 31, 2019 was 14,885 boe per day (comprised of 36 percent condensate and 43 percent total liquids) compared to 73 boe per day for the three months ended December 31, 2018. Production for the year ended December 31, 2019 was 4,762 boe per day (comprised of 37 percent condensate and 45 percent total liquids) compared to 91 boe per day for the year ended December 31, 2018. The increase in

2019 comparative periods was a result of the Company bringing on production from its North of the Wapiti River wells in mid-September 2019. All production in the 2018 comparative periods relates to Predecessor Pipestone Oil Corp. test production volumes.

Sales

($ thousands, except per unit amounts)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
	$	$	**$**	$
Crude oil	**339**	-	**1,257**	-
Condensate	**34,598**	59	**44,552**	1,628
Other NGL	**1,366**	-	**1,802**	-
Total NGL	**35,964**	59	**46,354**	1,628
Natural gas	**12,493**	-	**14,910**	-
Total	**48,796**	59	**62,521**	1,628
Average realized prices before hedging and transportation				
Crude oil *($/bbl)*	**62.17**	-	**66.91**	-
Condensate *($/bbl)*	**71.20**	8.60	**70.01**	49.11
Other NGL *($/bbl)*	**13.38**	-	**14.42**	-
Total NGL *($/bbl)*	**61.15**	8.60	**60.89**	49.11
Natural gas *($/Mcf)*	**2.68**	-	**2.59**	-
Combined average *($/boe)*	**35.63**	8.60	**35.97**	49.11

Sales for the three months ended December 31, 2019 were $48.8 million compared to $0.1 million for the three months ended December 31, 2018. Sales for the year ended December 31, 2019 were $62.5 million compared to $1.6 million for the year ended December 31, 2018. The increase in 2019 comparative periods was a result of the Company selling production from its North of the Wapiti River wells beginning in mid-September 2019. Furthermore, all sales in the 2018 comparative periods relate to Predecessor Pipestone Oil Corp. test production volumes, and thus is not a meaningful comparative.

Benchmark Pricing

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
	$	$	**$**	$
Average crude oil prices				
WTI crude oil *(US$/bbl)* [(1)]	**56.95**	58.79	**57.01**	64.82
WTI crude oil *(C$/bbl)*	**75.16**	77.75	**75.66**	83.94
Average condensate prices				
Edmonton Condensate *(C$/bbl)*	**74.95**	60.32	**71.40**	78.78
Average natural gas prices				
AECO 5A natural gas *(C$/GJ)* [(2)]	**2.35**	1.57	**1.70**	1.52
Chicago City Gate natural gas *(C$/GJ)* [(3)]	**2.77**	3.63	**3.04**	3.02
Average foreign exchange rate				
Exchange rate *(US$/C$)*	**0.76**	0.76	**0.75**	0.77

(1) WTI refers to the West Texas Intermediate crude oil price.
(2) AECO refers to the Alberta Energy Company natural gas price. 5A is a simple average of the daily spot prices.
(3) Chicago City Gate refers to the Chicago Index Futures natural gas price.

Pipestone Energy's condensate production is delivered and sold in Edmonton, Alberta, through the Pembina pipeline system. The price of WTI for crude oil sales at Cushing, Oklahoma is the primary benchmark for crude oil pricing in North America. Despite some recent volatility, the price that Alberta condensate producers receive for their condensate production has historically been highly correlated to the price of WTI, adjusted for Edmonton differentials, external supply and demand, changes in Canada-U.S. exchange rates, transportation costs and quality. As such, the Company has hedged certain expected future volumes to WTI directly in C$ and the Company has also hedged a subset of volumes to the differential between WTI and Edmonton Condensate ("EdCon"). EdCon refers to the Enbridge condensate pool price for liquids sales at Edmonton, Alberta which is the primary reference price for condensate in Western Canada (see the *"Commodity Price Risk Management"* section).

The AECO 5A price is the primary benchmark for the Company's current natural gas sales. The AECO 5A differentials to other North American benchmarks can fluctuate significantly, primarily due to limited economic transportation and options out of Western Canada, increasing domestic production and limited access to local storage facilities. Prior to the September 2019 start-up of the North of the Wapiti River production, Pipestone Energy primarily utilized its firm service contract for 5.0 MMcf per day of natural gas to Chicago through the Alliance Pipeline (which represented the majority of the Company's natural gas production during nine months ended September 30, 2019).

Royalties

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Royalties *($ thousands)*	**2,193**	27	**2,912**	137
Per boe *($)*	**1.60**	3.96	**1.68**	4.14
Percentage of sales	**4.5%**	45.8%	**4.7%**	8.4%

Pipestone Energy's royalty burden is predominately paid to the Province of Alberta, with minimal gross over-riding royalties applicable on a portion of the Company's production sales. The 2019 royalty rates are indicative of royalty rates on new production in Alberta under the Modernized Royalty Framework.

Royalties for the three months ended December 31, 2019 were $2.2 million compared to $27 thousand for the three months ended December 31, 2018. Royalties for the year ended December 31, 2019 were $2.9 million compared to $0.1 million for the year ended December 31, 2018. The increase in royalties paid in 2019 comparative periods was a result of the significantly increased production volumes generated from the Company's North of the Wapiti River wells which was brought on in mid-September 2019.

Operating Expense

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018 (1)
	$	$	**$**	$
Operating expense *($ thousands)*	**18,507**	80	**24,140**	337
Per boe *($)*	**13.51**	11.57	**13.89**	10.16

(1) IFRS 16, *Leases*, was adopted on January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

The majority of Pipestone Energy's operating costs are comprised of third-party gathering and processing fees with field site operation and supervision activities, chemicals, maintenance, fuel, lease rentals, insurance and property taxes making up the balance. Fees associated with third-party gathering and processing represent approximately 80 percent of Pipestone Energy's operating costs for the three months and year ended December 31, 2019.

Operating expenses for the three months ended December 31, 2019 were $18.5 million compared to $0.1 million for the three months ended December 31, 2018. Operating expenses for the year ended December 31, 2019 were $24.1 million compared to $0.3 million for the year ended December 31, 2018. The increase in operating expenses in 2019 was a result of the Company's bringing on production from its North of the Wapiti River wells in mid-September 2019. The Company's third-party gathering and processing commitments began concurrent with production start-up.

With the application of IFRS 16 Pipestone Energy's operating expenses associated with third-party compressor fees were reduced by $1.5 million ($1.09 per boe) and $1.5 million ($0.76 per boe) for the three months and year ended December 31, 2019, respectively.

The Q4 2019 operating expense of approximately $13.51 per boe is not expected to be indicative of Pipestone Energy's long-term operating expense rates. The Company experienced higher operating expenses in the latter part of 2019 due to a number of factors which included: certain fixed operating costs being spread over limited 2019 production volumes and the largest impact being costs from start-up challenges at third-party processing facilities. Our third-party midstream partners experienced inconsistent run-times, unplanned outages, unplanned curtailments and high shrinkage rates on production delivered by Pipestone Energy during the three months and year ended December 31, 2019. Pipestone Energy expects these start-up issues to dissipate and has also renegotiated certain third-party gathering and processing fee structures to reduce both the quantum and the variability of its operating costs per boe in 2020.

Transportation Expense

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Transportation expense *($ thousands)*	**4,477**	-	**7,156**	-
Per boe *($)*	**3.26**	-	**4.12**	-

Pipestone Energy has entered into various firm service contracts to transport its current and future expected production volumes. Transportation expense primarily consist of tolls on the Pembina Peace, NGTL and Alliance pipeline systems. Pipestone Energy incurs transportation charges on the sales volumes that it delivers to specified sales hubs that are beyond its third-party processing facilities under committed agreements.

Transportation expenses for the three months ended December 31, 2019 were $4.5 million compared to $nil for the three months ended December 31, 2018. Transportation expenses for the year ended December 31, 2019 were $7.2 million compared to $nil for the year ended December 31, 2018. The increase in transportation expenses in 2019 comparative periods was a result of the Company's transportation commitments commencing to accommodate initial sales volumes produced from the increased production brought on beginning in September 2019.

During the nine months ended September 30, 2019, Pipestone Energy had very low actual transported volumes as production was limited to the legacy production from the Corporate Acquisition and the third-party plant this production was processed through experienced several extended shut-downs, however, the firm service and take-or-pay condensate and gas handling commitments listed below, remained effective, and the resulting transportation expense for 2019 was high on a per boe basis due to the take-or-pay exposure. These firm service contracts included:

- Take-or-pay gas handling agreement for 5 MMcf per day of processed gas on the Alliance pipeline to the Alliance Chicago Exchange Hub until October 31, 2021;
- Firm service agreement providing for the transportation of 3.5 MMcf per day through the TCPL system until October 2021; and
- Firm service agreement providing for the transportation of 1,000 bbls per day of condensate through Pembina's pipeline system until September 2027.

In Q4 2019 Pipestone Energy continued to incur costs related to the above-mentioned contracts, as well as additional transportation costs on its initial North of the Wapiti River gas volumes delivered through the NGTL system and on its liquids volumes delivered through the Pembina Peace pipeline. The transportation expense per boe for Q4 2019 improved compared to 2019 full year due to better utilization of the firm commitments in place. The Company expects its transportation expense per boe to further improve into 2020 as it delivers higher volumes and is able to deliver those volumes more consistently.

Commodity Price Risk Management

During 2019 Pipestone Energy began to execute its commodity price risk management program, which is primarily designed to reduce cash flow volatility, enhance certainty on funding available for the Company's capital expenditure program and service debt.

Mitigation of cash flow volatility is an integral component of the Company's business strategy. Business conditions are monitored regularly and reviewed with the Board of Directors to establish risk management guidelines used by management in carrying out the Company's strategic risk management program.

Pipestone Energy continues to implement an ongoing hedge program, focused on its forecast liquids and naturals gas production. Pipestone Energy utilizes a variety of hedging structures, including fixed price swaps, collars, and product differential hedges. To date, Pipestone Energy has entered into hedges with respect to benchmark WTI, AECO and EdCon (Edmonton condensate) directly. Price and volume targets for the Company's hedge portfolio are established based on macro supply and demand fundamental analysis, Pipestone Energy's future production expectations and target development rates.

The Company also entered into forward swaps on the differential between the Net Canadian Energy Monthly Index Edmonton C5+ price and WTI, traded in US$ per barrel on the Chicago Mercantile Exchange. A fixed-price Edmonton C5+ swap can be generated through the combination of a WTI swap and an Edmonton C5+ differential swap. This hedge product was added to Pipestone Energy's portfolio during Q2 2019.

The Company has elected not to use hedge accounting and, accordingly, the fair value of the commodity financial derivative instruments is recorded at each period-end. The fair value may change substantially from period to period depending on commodity forward strip prices for the contracts outstanding at the balance sheet date. The change in fair value from period-end to period-end is reflected in profit or loss for that period. As such, if benchmark prices rise during the period, the Company records a loss based on the change in price multiplied by the volume hedged. If benchmark prices fall during the period, the Company records a gain. The prices used to record the actual gain or loss are subject to an adjustment for volatility. Pipestone Energy's financial results should be viewed with the understanding that the estimated future gain or loss on financial derivative instruments is recorded in the current period's profit or loss, while the estimated future value of the underlying physical sales is not.

Commodity financial derivative instruments

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Realized gain (loss) on commodity financial derivative instruments *($ thousands)*				
Condensate	**(601)**	-	**(601)**	-
Crude oil	**777**	-	**655**	-
Natural gas	**(873)**	-	**(873)**	-
Total	**(697)**	-	**(819)**	-
Per boe *($)*	**(0.51)**	-	**(0.47)**	-
Unrealized gain (loss) on commodity financial derivative instruments *($ thousands)*				
Condensate	**(3,283)**	-	**(2,663)**	-
Crude oil	**(10,746)**	-	**3,092**	-
Natural gas	**(253)**	-	**(1,320)**	-
Total	**(14,282)**	-	**(891)**	-
Per boe *($)*	**(10.43)**	-	**(0.51)**	-

During the three months ended December 31, 2019, the Company incurred a realized loss on commodity financial derivative instruments of $0.7 million compared to $nil during the three months ended December 31, 2018. The realized loss on commodity financial derivative instruments was due primarily to the strengthening of AECO 5A prices and the tightening of the Edmonton condensate differential to WTI in Q4 2019. The realized losses were partially offset by realized gains on the Company's WTI swaps. The Company did not have any commodity financial derivative instruments in place in 2018.

During the year ended December 31, 2019, the Company incurred a realized loss on commodity financial derivative instruments of $0.8 million compared to $nil during the year ended December 31, 2018. The realized loss on commodity financial derivative instruments was due primarily to the strengthening of AECO 5A prices and the tightening of the Edmonton condensate differential to WTI in Q4 2019. The realized losses were partially offset by realized gains on the Company's WTI swaps. The Company did not have any commodity financial derivative instruments in place in 2018.

During the three months ended December 31, 2019, the Company incurred an unrealized loss on commodity financial derivative instruments of $14.3 million compared to $nil during the three months ended December 31, 2018. The unrealized loss on commodity financial derivative instruments was due primarily to the strengthening of AECO 5A and WTI prices as well as the tightening of the Edmonton condensate differential to WTI near the end of 2019. The Company did not have any commodity financial derivative instruments in place in 2018.

During the year ended December 31, 2019, the Company incurred an unrealized loss on commodity financial derivative instruments of $0.9 million compared to $nil during the year ended December 31, 2018. The unrealized loss on commodity financial derivative instruments was due primarily to the strengthening of AECO 5A prices and the tightening of the Edmonton condensate differential to WTI near the end of 2019. The unrealized losses were partially offset by unrealized gains on the Company's WTI swaps. The Company did not have any commodity financial derivative instruments in place in 2018.

The Company had the following weighted-average condensate, crude oil and natural gas commodity financial derivative instruments at December 31, 2019:

	C$ WTI collars		C$ WTI swaps		EdCon basis swaps		AECO 5A swaps	
Term	bbls/d	C$/bbl	bbls/d	C$/bbl	bbls/d	US$/bbl	GJ/d	C$/GJ
Jan. – Mar. '20	731	70.47 – 80.45	2,800	79.11	3,000	(4.95)	31,647	1.94
Apr. – Jun. '20	500	73.00 – 81.60	2,800	79.11	2,000	(5.63)	40,000	1.60
Jul. – Sept. '20	-	-	3,400	78.15	1,000	(5.75)	40,000	1.60
Oct. – Dec. '20	-	-	2,750	77.90	1,000	(5.75)	28,396	1.65
Jan. – Dec. '21	-	-	-	-	-	-	2,500	1.95
Jan. – Dec. '22	-	-	-	-	-	-	2,500	1.95

Subsequent to December 31, 2019, the Company unwound the following commodity hedges for total proceeds received of $3.9 million to crystalize the value of a portion of its contracts in place:

	C$ WTI swaps	
Term	bbls/d	C$/bbl
Jul. – Dec. '20	250	77.25
Jul. – Nov. '20	1,250	76.74
Jan. – Nov. '20	500	78.55
	C$ WTI collars	
Term	bbls/d	C$/bbl
Jan. – May '20	250	73.00 – 81.20

Subsequent to December 31, 2019, the Company entered the following commodity hedge:

	C$ WTI swaps	
Term	bbls/d	C$/bbl
Apr. – Aug. '20	250	73.10

Interest rate financial derivative instruments

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
	$	$	**$**	$
Realized loss on interest rate financial derivative instruments *($ thousands)*	**(192)**	-	**(192)**	-
Per boe *($)*	**(0.14)**	-	**(0.11)**	-
Unrealized gain (loss) on interest rate financial derivative instruments *($ thousands)*	**846**	(16)	**1,318**	(316)
Per boe *($)*	**0.62**	(2.37)	**0.76**	(9.54)

Pipestone Energy's interest rate financial derivative instruments were entered into as a condition of the $198.5 million first lien credit facilities (the "Credit Facility") which were replaced with the RBL in December 2019. The instruments are comprised of floating to fixed interest rate swaps with the lending institutions, which resulted in the term-debt bearing fixed interest rates. Due to the nature of the bank debt and the swaps being with the lending institutions, the realized portion of the interest rate financial derivative instruments is recorded as financing expense.

During the three months ended December 31, 2019, the Company incurred a realized loss on interest rate financial derivative instruments of $0.2 million compared to $nil during the three months ended December 31, 2018.

During the year ended December 31, 2019, the Company incurred a realized loss on interest rate financial derivative instruments of $0.2 million compared to $nil during the year ended December 31, 2018.

During the three months ended December 31, 2019, the Company incurred an unrealized gain on interest rate financial derivative instruments of $0.8 million compared to an unrealized loss of $16 thousand during the three months ended December 31, 2018.

During the year ended December 31, 2019, the Company incurred an unrealized gain on interest rate financial derivative instruments of $1.3 million compared to an unrealized loss of $0.3 million during the year ended December 31, 2018.

General and Administrative (G&A) Expenses

($ thousands, except per boe amounts)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
	$	$	**$**	$
Gross G&A expenses	**2,824**	5,755	**12,423**	6,957
Capitalized G&A	**(756)**	-	**(3,365)**	-
Overhead recoveries	**(151)**	-	**(183)**	-
G&A expenses	**1,917**	5,755	**8,875**	6,957
Per boe	**1.40**	851.15	**5.11**	209.92

G&A expenses primarily consist of the Company's overhead costs incurred to support its ongoing operations and planned future operations. Capitalized G&A is directly attributable to the development of the Pipestone Energy assets. Overhead recoveries relate to recovered amounts from partners for operating administration costs as well as capital programs. Capitalized G&A and overhead recoveries are consistent with industry practice. For the quarter and full-year 2019 Pipestone Energy capitalized 27 percent of gross G&A expenses.

During the three months ended December 31, 2019, the Company's gross G&A expenses were $2.8 million compared to $5.8 million for the three months ended December 31, 2018. G&A expenses in Q4 2018 were disproportionately high.

During the year ended December 31, 2019, the Company's gross G&A expenses increased to $12.4 million from $7.0 million for the year ended December 31, 2018. G&A expenses were higher than in the comparative period of 2018 predominantly due to higher employee and consulting expenses associated with increased activity in 2019 and a number of one-time integration expenditures relating to the Corporate Acquisition.

Although lower than the annualized 2019 expense, the Q4 2019 $1.40 per boe expense burden is high at this stage of Pipestone Energy's development as the Company incurred various one-time costs, and added capabilities as it scaled its business in anticipation of increased production volumes that were ramped up in the fall of 2019. The Company expects that it will modestly reduce its per boe G&A expense in 2020.

Transaction Expenses

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Transaction *($ thousands)*	**-**	2,536	**4,305**	2,536
Per boe *($)*	**-**	375.15	**2.48**	76.54

During the three months ended December 31, 2019, the Company incurred $nil transaction expenses compared to $2.5 million during the three months ended December 31, 2018. The decrease was due to the Company not having any corporate transactions occur in Q4 2019.

During the year ended December 31, 2019, the Company incurred $4.3 million in transaction expenses compared to $2.5 million during the year ended December 31, 2018. The increase in 2019 was due to the transaction expenses incurred for services related to the Corporate Acquisition, which closed January 4, 2019. These included fees for financial advisors, legal consultations, due diligence and reservoir engineers. In aggregate over 2018 and 2019 the Company incurred a total of $6.8 million in transaction expenses related to the Corporate Acquisition.

Share-based compensation

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
Share-based compensation *($ thousands)*	**423**	-	**754**	-
Per boe *($)*	**0.31**	-	**0.43**	-

Share-based compensation relates to stock options, performance share units (PSUs), restricted share units (RSUs) granted to employees, officers and directors, commencing in 2019. The employee stock purchase plan (ESPP) commenced Q4 2019.

During the three months ended December 31, 2019, the Company incurred share-based compensation of $0.4 million compared to $nil for the comparative period in 2018. During the year ended December 31, 2019, the Company incurred share-based compensation of $0.8 million compared to $nil for the comparative period in 2018.The comparative period increases were due to the Company launching its long-term incentive plan in 2019.

Exploration and Evaluation ("E&E") Expenses

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018
	$	$	**$**	$
E&E *($ thousands)*	**1,615**	-	**3,315**	-
Per boe *($)*	**1.18**	-	**1.91**	-

During the three months ended December 31, 2019, the Company incurred E&E expenses of $1.6 million compared to $nil for the comparative period in 2018. During the year ended December 31, 2019, the Company incurred E&E expenses of $3.3 million compared to $nil for the comparative period in 2018. The increase was due to mineral rights expiries that occurred during Q3 and Q4 2019 related to undeveloped land acquired in the Corporate Acquisition.

Depletion and Depreciation ("D&D") Expenses

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
	$	$	**$**	$
Depletion *($ thousands)*	**12,412**	70	**16,370**	351
Per boe *($)*	**9.06**	10.34	**9.42**	10.60
Depreciation – ROU lease assets *($ thousands)*	**1,065**	-	**1,531**	-
Per boe *($)*	**0.78**	-	**0.88**	-
Depreciation – Corporate assets *($ thousands)*	**26**	-	**70**	25
Per boe *($)*	**0.02**	-	**0.04**	0.75
Total D&D expenses *($ thousands)*	**13,503**	70	**17,971**	376
Per boe *($)*	**9.86**	10.34	**10.34**	11.35

D&D expenses primarily consist of depletion of Company liquids and natural gas properties on a unit-of-production basis over total proved plus probable reserves before royalties. The unit-of-production rate takes into account expenditures incurred to date, together with estimated future development expenditures required to develop those proved plus probable reserves. This rate, calculated at a component level, is then applied to Pipestone Energy's production volume to determine D&D in a given period. Management believes that this method of calculating D&D expenses over each boe is equivalent with its proportionate share of the cost of capital invested over the total estimated life of the related asset as represented by proved plus probable reserves. Future development costs included during the three months ended December 31, 2019 are $1,114.0 million.

D&D expenses include depreciation of the Company's ROU assets on a straight-line basis over the shorter of the estimated useful life or the lease term. The Company's D&D expense increased marginally from the comparative periods in 2018 due to the introduction of ROU asset amortization as a result of the adoption of IFRS 16, *Leases*, as of January 1, 2019.

During the three months ended December 31, 2019, the Company incurred D&D expenses of $13.5 million compared to $0.1 million for the comparative period in 2018. The increase was due to the ramp-up in production volumes in mid-September 2019 partially offset by a lower depletion rate per boe due to significantly reduced future development costs associated with the Company's reserves at December 31, 2019.

During the year ended December 31, 2019, the Company incurred D&D expenses of $18.0 million compared to $0.4 million for the comparative period in 2018. The increase was due to the ramp-up in production volumes in mid-September 2019 partially offset by a lower depletion rate per boe due to significantly reduced future development costs associated with the Company's reserves at December 31, 2019.

Financing Expense

($ thousands, except per boe amounts)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018 [(1)]
	$	$	**$**	$
Letter of credit fees	**229**	-	**1,639**	-
Interest on bank debt	**3,109**	-	**9,432**	141
Bank charges	**33**	4	**62**	5
Lease interest expense	**1,101**	-	**1,239**	-
Cash financing expense	**4,472**	4	**12,372**	146
Interest on bank debt	**-**	1,061	**-**	2,693
Accretion on decommissioning provisions	**28**	8	**110**	33
Amortization of financing costs	**4,419**	188	**6,178**	602
Non-cash financing expense	**4,447**	1,257	**6,288**	3,328
Total financing expense	**8,919**	1,261	**18,660**	3,474
Cash financing expense, per boe	**3.27**	0.34	**7.11**	4.39
Non-cash financing expense, per boe	**3.25**	185.96	**3.62**	100.41

(1) IFRS 16, *Leases*, was adopted on January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

During the three months ended December 31, 2019, the Company incurred total financing expenses of $8.9 million compared to $1.2 million for the comparative period in 2018. The increase was due to additional indebtedness in 2019.

During the year ended December 31, 2019, the Company incurred total financing expenses of $18.7 million compared to $3.5 million for the comparative period in 2018. The increase was due to additional indebtedness in 2019 as well as financing costs associated with the extinguishment of the Company's old term debt. All previously unamortized financing costs were recognized as an expense in Q4 2019 per IFRS 9.

Interest on bank debt is the amount charged by Pipestone Energy's lending institutions.

Lease interest pertains to the interest rate implicit in the lease, or, if that rate cannot be determined, the Company's incremental borrowing rate. The interest rate applicable to each lease is applied to the lease liability and applied to each lease payment.

Accretion on decommissioning provisions increased from the 2018 comparative period as a result of having more wells, both as a result of drilling and from the Corporate Acquisition.

Amortization of financing costs relate to the bank due diligence fees related to Pipestone Energy's bank debt and the initial mark-to-market value of the interest rate swaps associated with the setup of the Credit Facility.

The current per boe expense burden for both the cash and non-cash financing expense is high at this stage of Pipestone Energy's development as the costs are spread over the relatively limited production volumes.

Financing Income

	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018
	$	$	**$**	$
Financing income *($ thousands)*	**267**	83	**1,038**	325
Per boe *($)*	**0.19**	12.28	**0.60**	9.81

Financing income relates to interest earned on cash held in bank accounts.

During the three months ended December 31, 2019, the Company earned financing income of $0.3 million compared to $0.1 million for the comparative period in 2018. Financing income was higher in 2019 than in 2018, due to higher bank balances.

During the year ended December 31, 2019, the Company earned financing income of $1.0 million compared to $0.3 million for the comparative period in 2018. Financing income was higher in 2019 than in 2018, due to higher cash balances.

Income Tax

The deferred income tax recoveries were $3.7 million and $11.1 million for the respective three months and year ended December 31, 2019, compared to recoveries of $Nil and $0.1 million in the respective 2018 periods. The recovery in the year ended December 31, 2019 is largely due to a $3.2 million benefit associated with a previously unrecognized deferred income tax asset now being recognized and applied against deferred income tax liabilities acquired in the Corporate Acquisition, as well as the reductions in the Alberta corporate income tax rate.

Pipestone Energy's estimated consolidated tax pools are summarized as follows:

($ thousands)	**As at December 31, 2019**	As at December 31, 2018
	$	$
Canadian oil and gas property expense	**31,667**	17,056
Canadian development expense	**118,410**	64,806
Canadian exploration expense	**46,165**	25,969
Non-capital losses	**235,957**	65,323
Undepreciated capital cost ("UCC") pools (1)	**75,398**	25,438
Debt and share issuance costs	**3,897**	1,939
	511,494	200,531

(1) Substantially all the Company's UCC pools relate to Class 41 assets, which are deductible at a rate of 25 percent per year.

The above tax pools include non-capital losses that expire in 2024 through 2038.

Loss

The Company incurred losses of $13.1 million ($0.07 per share basic and diluted) and $14.0 million ($0.07 per share basic and diluted) for the respective three months and year ended December 31, 2019, compared to losses of $9.6 million ($0.16 per share basic and diluted) and $12.1 million ($0.22 per share basic and diluted) for the respective comparative periods in 2018. The losses in 2019 and 2018 resulted mainly from transaction costs and interest expense on bank debt. The loss for the year ended December 31, 2019 was partially offset from one-time income tax gains associated with reductions in the Alberta corporate income tax rate and a previously unrecognized deferred income tax asset now being recognized and applied against deferred income tax liabilities acquired in the Corporate Acquisition.

Liability Management Rating ("LMR") and Decommissioning Provisions

At December 31, 2019, Pipestone Energy's Alberta LMR rating was positive 9.21, At December 31, 2019, the Company's total decommissioning provision was $6.7 million or 1.3 percent of its total property and equipment balance. Pipestone Energy believes it is well positioned with respect to it long-term abandonment and reclamation obligations, the majority of which are expected to be incurred between the year 2045 and 2055.

Supplemental Information

The following table summarizes key financial and operating information for the periods indicated.

Netback Analysis

	Three months ended December 31,		Year ended December 31,	
	2019	2018	**2019**	2018 [1]
	$	$	**$**	$
Average sales price of liquids and natural gas	**35.63**	8.60	**35.97**	49.11
Royalties	**(1.60)**	(3.96)	**(1.68)**	(4.14)
Operating expense	**(13.51)**	(11.57)	**(13.89)**	(10.16)
Transportation expense	**(3.26)**	-	**(4.12)**	-
Operating netback [2]	**17.26**	(6.93)	**16.28**	34.81
G&A expense	**(1.40)**	(851.15)	**(5.11)**	(209.92)
Transaction costs	**-**	(375.15)	**(2.48)**	(76.54)
Realized loss on commodity financial derivative instruments	**(0.51)**	-	**(0.47)**	-
Realized loss on interest rate financial derivative instruments	**(0.14)**	-	**(0.11)**	-
Financing income	**0.19**	12.28	**0.60**	9.81
Financing expense	**(3.27)**	(0.34)	**(7.11)**	(4.39)
Funds flow netback [2]	**12.13**	(1,221.29)	**1.60**	(246.23)
Financing expense – non-cash	**(3.25)**	(185.96)	**(3.62)**	(100.41)
D&D expense	**(9.86)**	(10.34)	**(10.34)**	(11.35)
E&E expense	**(1.18)**	-	**(1.91)**	-
Share-based compensation	**(0.31)**	-	**(0.43)**	-
Unrealized gain (loss) on interest rate financial derivative instruments	**0.62**	(2.37)	**0.76**	(9.54)
Unrealized loss on commodity financial derivative instruments	**(10.43)**	-	**(0.51)**	-
Deferred income tax recovery	**2.68**	-	**6.39**	1.75
Loss per boe	**(9.60)**	(1,419.96)	**(8.06)**	(365.78)

(1) IFRS 16, *Leases*, was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

(2) See "Non-GAAP measures".

The per boe costs related to the netback for the year ended December 31, 2019 were high given the stage of Pipestone Energy's development, as fixed costs were spread over the limited production volumes.

Selected Quarterly Information

Three months ended	**Dec. 31, 2019**	**Sept. 30, 2019**	**June 30, 2019**	March 31, 2019	Dec. 31, 2018 (2)(4)	Sept. 30, 2018 (2) (4)	June 30, 2018 (2) (4)	March 31, 2018 (2) (4)
Financial ($ thousands, except per share amounts and share numbers)								
Sales of liquids and natural gas	**48,796**	**7,808**	5,917	460	59	-	598	971
Cash from (used in) operating activities	**30,750**	**(6,626)**	(777)	(12,785)	(3,490)	(361)	(180)	163
Adjusted funds flow from (used in) operations	**16,608**	**(2,734)**	(2,423)	(8,663)	(8,260)	(512)	132	480
Per share, basic and diluted *($)* (1)	**0.09**	**(0.01)**	(0.01)	(0.05)	(0.14)	(0.01)	0.00	0.01
Income (loss)	**(13,143)**	**(1,409)**	4,869	(4,302)	(9,603)	(1,349)	(539)	(631)
Per share, basic and diluted *($)* (1)	**(0.07)**	**(0.01)**	0.03	(0.02)	(0.16)	(0.03)	(0.01)	(0.01)
Capital expenditures	**36,457**	**29,434**	46,835	49,468	60,252	5,428	13,026	30,558
Total assets *(end of quarter)*	**663,816**	**607,287**	579,297	531,994	216,300	147,240	128,644	144,740
Working capital (deficit) *(end of quarter)*	**(12,015)**	**20,893**	(8,026)	2,411	(20,180)	10,332	(2,630)	10,264
Bank debt *(end of quarter)*	**163,048**	**156,983**	115,754	80,735	53,436	52,187	30,992	30,181
Shareholders' equity *(end of quarter)*	**370,075**	**382,867**	383,843	378,896	114,058	85,661	87,010	87,549
Weighted-average basic shares outstanding *(000s)* (1)	**189,743**	**189,627**	187,096	184,540	60,707	52,782	52,782	52,782
Weighted-average diluted shares outstanding *(000s)* (1)	**189,777**	**189,627**	187,116	184,540	60,707	52,782	52,782	52,782
Operations								
Total production *(boe/d)*	**14,885**	**2,467**	1,407	152	73	-	106	186
Condensate and crude oil *(% of total production)*	**36**	**45**	42	54	100	-	100	100
Total liquids *(% of total production)*	**43**	**51**	49	65	100	-	100	100
Average realized price *(per boe)*	**35.63**	**34.40**	42.62	33.53	8.60	-	61.94	58.00
Operating netback *(per boe)* (3)	**17.26**	**11.61**	20.92	(45.09)	(6.93)	-	51.25	46.54
Funds flow netback *(per boe)* (3)	**12.13**	**(12.04)**	(18.93)	(631.58)	(1,221.29)	-	13.50	28.69

(1) The number of common shares have been adjusted retrospectively to reflect the 10:1 share consolidation, as well as the 0.5996 exchange ratio, as part of the Corporate Acquisition.

(2) IFRS 16, *Leases*, was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

(3) See "Non-GAAP measures".

(4) The comparative figures presented for 2018 and 2017 are that of the predecessor company, Predecessor Pipestone.

Inherent to the nature of the oil and natural gas industry, fluctuations in Pipestone Energy's quarterly sales of liquids and natural gas, adjusted funds flow from or used in operations, and income or loss are primarily caused by variations in production volumes, realized commodity prices and the related impact on royalties, realized and unrealized gains or losses on financial instruments, changes in per-unit expenses, and deferred income taxes. Please refer to "Financial and Operating Results" above for an explanation of changes.

Selected Annual Information

Years ended	**Dec. 31, 2019**	Dec. 31, 2018[(1)]	Dec. 31, 2017[(1)]
($ thousands)			
Sales of liquids and natural gas	**62,521**	1,628	958
Income (loss) and comprehensive income (loss)	**(13,985)**	(12,122)	155
Total assets	**663,816**	216,300	99,954
Total non-current liabilities	**228,304**	56,730	965

(1) The comparative figures presented for 2018 and 2017 are that of the predecessor company, Pipestone Oil Corp.

Share Capital

As at the date of this MD&A, the Company had 189.9 million common shares, 175.2 million warrants, 1.6 million stock options, 0.6 million PSUs and 0.9 million RSUs outstanding. Each warrant is exercisable for 0.1 common shares of the Company.

Related Party Transactions

During the year ended December 31, 2019, Pipestone Energy incurred $3.6 million of general and administrative expenses from CNOR LP. At December 31, 2019, $3.0 million (December 31, 2018 – $4.8 million) was included in accounts payable and accrued liabilities and was due under normal credit terms. All related-party transactions are recorded at the exchange amount. At December 31, 2019, CNOR LP held approximately 55 percent of Pipestone Energy's issued and outstanding common shares.

Liquidity and Capital Resources

At December 31, 2019, the Company had an adjusted working capital deficit of $6.0 million (December 31, 2018 – adjusted working capital deficit of $20.2 million), excluding the interest rate and commodity financial derivative instrument assets and liabilities, as well as lease liabilities. Cash from operating activities for the three months and year ended December 31, 2019 was $30.8 million and $10.6 million, respectively. Adjusted funds flow from operations for the three months and year ended December 31, 2019 was $16.6 million and $2.8 million, respectively.

Available Funding

($ thousands)	**As at December 31, 2019**	2018 [(1)]
	$	$
Current assets	**53,422**	23,784
Current liabilities	**65,437**	45,512
Working capital surplus (deficit)	**(12,015)**	(21,728)
Less: current asset commodity financial derivative instruments	**(330)**	-
Plus: current liability commodity financial derivative instruments	**1,310**	-
Plus: current liability interest rate financial derivative instruments	**1,439**	1,548
Plus: current lease liabilities	**3,617**	-
Adjusted working capital surplus (deficit) [(2)]	**(5,979)**	(20,180)
Plus: Credit Facility capacity [(3)]	**47,870**	6,228
Available funding (deficit) [(2)]	**41,891**	(13,952)

(1) IFRS 16, *Leases*, was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

(2) See "Non-GAAP measures".

(3) As at December 31, 2019, Pipestone Energy has a $195.0 million syndicated revolving facility, which is reduced by $150.0 million of principal drawn. At December 31, 2019, the Company also has a $30.0 million bi-lateral operating facility, which is reduced by $13.0 million of principal drawn and $14.1 million in outstanding letters of credit issued, which reduce the available funding on the operating facility. This credit facility capacity excludes the accordion feature on Pipestone's syndicated revolving facility, which provides for a $25.0 million increase to the borrowing capacity, subject to the mutual consent of Pipestone's lenders.

Bank Debt

On December 12, 2019, Pipestone Energy entered into a $225.0 million RBL comprised of a $195.0 million syndicated facility (the “Syndicated Facility”) and a $30.0 million operating facility (the “Operating Line”). The Syndicated Facility includes an accordion feature, which provides for a $25.0 million increase to the borrowing capacity, subject to the mutual consent of its lenders.

At December 31, 2019, the Company had $150.0 million drawn against the Syndicated facility and $13.0 million drawn on the Operating Line.

In addition to the balance of $163.0 million, the Company had $14.1 million in outstanding letters of credit issued against its Operating Line which reduces the available funding on the Operating Line.

The borrowing base on the facility will be redetermined bi-annually in the spring and fall each year and is based on the lenders' assessment of our reserves and future commodity prices. If not extended by any or all lenders, the commitments of such non-extending lenders under the RBL will cease to revolve, all outstanding advances thereunder owing to such non-extending lenders will become repayable in one year from the term date and the margins owing on such outstanding advances will increase by 0.50%. In the event the borrowing base is reduced below amounts outstanding, any excess will become due and payable 60 days subsequently.

Borrowing base redetermination will be required if the Company’s Liability Management Rating (LMR) or equivalent measurement falls below 2.00 in any material jurisdiction where Pipestone Energy operates. The Company’s LMR rating was 9.21 in Alberta on the closing date of the RBL financing.

Advances under the RBL are available by way of Canadian prime rate, and U.S. base rate loans with interest rates between 0.50 percent and 2.50 percent over the bank's prime lending rate, as well as bankers' acceptances and London Inter-bank Offered Rate (LIBOR) loans, which are subject to stamping fees and margins ranging from 1.50 percent to 3.50 percent depending upon our senior debt to Earnings Before Interest, Taxes, Depreciation and Amortization (EBITDA) ratio calculated at our previous quarter end. Given the start-up nature of Pipestone Energy’s operations in 2019, for purposes of calculating EBITDA, the credit agreement allows for annualized EBITDA calculations for Q4 2019, Q1 2020, Q2 2020, and Q3 2020.

As at December 31, 2019, Pipestone’s applicable pricing included a 1.00 percent per annum margin on prime loans, a 2.00 percent per annum stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.45 percent per annum standby fee on the portion of the RBL that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual renewal.

The credit agreement contains customary borrowing base provisions and negative covenants including, but not limited to, restrictions on our ability to incur indebtedness, grant liens or security interests on assets, sell or otherwise transfer assets, make distributions, make investments or provide financial assistance and our ability to merge and consolidate with other companies or change our line of business, in each case, subject to certain exceptions.

The credit agreement contains customary positive covenants including, but not limited to, delivery of financial and other information to the lenders, maintenance of existence, payment of taxes and other claims, maintenance of properties and insurance, access to books and records by the lenders, compliance with applicable laws and regulations, including environmental laws, and further assurances and provision of additional collateral and guarantees.

The credit agreement provides that, upon the occurrence of certain events of default, our obligations thereunder may be accelerated and the lending commitments terminated. Such events of default include payment defaults to the lenders, covenant defaults, inaccuracies of representations and warranties, bankruptcy and insolvency proceedings, business suspension, material money judgments, cross defaults, change of control and other customary events of default. As is customary, the facility contains material adverse change clauses which would enable the lenders to demand immediate repayment of amounts outstanding if determined to represent an event of default.

The indebtedness under the credit agreement is secured by floating charges and a security interest against our current and future real and personal property. The Company does not currently have any material subsidiaries and, as such, no guarantees have been provided under the credit agreement.

The revolving period of the RBL currently ends on November 30, 2020 with an additional one-year term out period thereafter if the revolving period is not extended. An extension of the revolving period is subject to majority lender consent.

The RBL fully replaced Pipestone Energy's $198.5 million Credit Facility which was comprised of a $10.0 million revolving operating line, a $20.0 million letter of credit facility, and a $168.5 million delayed-draw term loan (the "Term Loan"). The Term Loan was funded in fixed tranches to fund capital expenditures and general corporate expenses. Interest on the operating line and letter of credit facility was payable in cash, while interest on the Term Loan is added to the debt balance.

The average rate of interest on the bank debt for the year ended December 31, 2019 was 8.3 percent.

Capital Management

The Company's objective for managing capital is to maintain a strong balance sheet and available funding while providing financial flexibility to fund sustaining capital and to fund future high-return development growth. Near-term development activities are anticipated to be funded by the Company's funds flow, cash on hand, potential divestitures or draws under the credit facilities.

Pipestone Energy manages its liquidity risk through its capital structure, cash flow forecasting and available credit.

The Company as indicated above has significant financial liabilities and commitments over the next one to two years. The Company believes in the short term that its financial requirements will be addressed through its current and future lending arrangements which were significantly enhanced by the RBL and an increase in future operating cash flows as production increases in 2020. The Company believes it will be successful in meeting its liquidity requirements, although uncertainty remains due to volatility in commodity prices and the economic environment, including uncertainty in accessing if required additional sources of equity or debt financing, as well as reserve and production risk.

The Company strives for a proportion of debt to future cashflow which appropriately balances the level of risk being incurred by its capital investments.

Commitments, Contractual Obligations and Contingencies

At December 31, 2019, as part of its normal operations, Pipestone Energy had committed to paying the following undiscounted amounts over the next five years and thereafter as follows:

($ Thousands)	2020	2021	2022	2023	2024	Thereafter
	$	$	$	$	$	$
Gathering commitments	9,759	10,255	10,334	10,334	10,340	49,658
Processing commitments	14,513	22,113	24,112	24,112	24,178	116,598
Transportation commitments	16,925	16,355	16,965	16,965	17,011	99,375
Total payments	**41,197**	**48,723**	**51,411**	**51,411**	**51,529**	**265,631**

Lease liabilities are recognized on the Company's consolidated balance sheet at their net present value. The gathering commitments, processing commitments, transportation commitments and interest on the lease liabilities are off-balance sheet arrangements in accordance with IAS 1, *Presentation of Financial Statements*.

Following the adoption of IFRS 16, *Leases*, on January 1, 2019, the Company recognized a lease liability on the consolidated statement of financial position for the majority of its non-cancellable lease arrangements. The Company elected to apply the practical expedient exemption to scope-out non-cancellable low-value and short-term lease arrangements. These out-of-scope contractual commitments are off-balance-sheet arrangements.

The following table details the undiscounted cash flows and contractual maturities of Pipestone Energy's lease liabilities, as at December 31, 2019:

	2019
	$
2020	9,845
2021	9,891
2022	9,410
2023	9,292
2024	9,292
Thereafter	42,995
Total undiscounted future lease payments	90,725
Amounts representing lease interest expense over the term of the lease	(36,808)
Present value of net lease payments	53,917

The Company is involved in legal claims arising in the normal course of business. The outcome of such claims cannot be predicted with certainty and management believes that it has appropriately assessed any impact to the financial statements.

Critical Accounting Judgments, Estimates and Policies

The Company's critical accounting judgements, estimates and policies are described in notes 2 and 3 to the December 31, 2019 annual consolidated financial statements. Certain accounting policies are identified as critical because they require management to make judgments and estimates based on conditions and assumptions that are inherently uncertain, and because the estimates are of material magnitude to revenue, expenses, adjusted funds flow from operations, income or loss and/or other important financial results. These accounting policies could result in materially different results should the underlying conditions change, or the assumptions prove incorrect.

Critical accounting estimates are those requiring management to make particularly subjective or complex judgments about inherently uncertain matters. Estimates and underlying assumptions are reviewed on an ongoing basis and any revisions to accounting estimates are recognized in the same period.

Management's assumptions are based on factors that, in management's opinion, are relevant and appropriate, and may change over time as operating conditions change.

New accounting standards

IFRS 16, *Leases*, replaced IAS 17, *Leases*, and IFRIC 4, *Determining Whether an Arrangement Contains a Lease*. IFRS 16 requires entities to recognize lease assets and obligations on the balance sheet. For lessees, IFRS 16 removes the classification of leases as either operating leases or finance leases, effectively treating nearly all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements and may continue to be treated as operating leases.

The Company adopted the standard on the effective date of January 1, 2019 and applied the modified retrospective approach which does not require restatement of prior period financial information as the cumulative effect of applying the standard to prior periods is recorded as an adjustment to opening retained earnings. On initial adoption, management 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 12 months as at January 1, 2019 as short-term leases.

- Account for lease payments as an expense and not recognize a right-of-use (ROU) asset if the underlying asset is of low dollar value.
- Apply hindsight in determining the lease term where the contract contains terms to extend or terminate the lease.

On adoption of IFRS 16, the Company recognized lease liabilities in relation to leases under the principles of the new standard. These liabilities were measured at the present value of the remaining leases payments, discounted using the Company's incremental borrowing rate as at January 1, 2019. The associated ROU asset was initially measured at the amount equal to the lease liability on January 1, 2019 with no impact on retained earnings.

Adoption of the new standard resulted in the recognition of an additional lease liability and corresponding ROU asset related to a field office lease. The impact of IFRS 16 is as follows:

- Lower operating expenses;
- Higher financing expenses due to the interest recognized on the lease obligation; and
- Higher depreciation expense related to the ROU asset.

The change in accounting policy affected the following items in the statement of financial position on January 1, 2019:

($ thousands)	January 1, 2019
	$
ROU asset presented in property and equipment	44
Current lease liability	33
Long-term lease liability	11

There are no other not-yet-effective IFRS or IFRIC interpretations that are expected to have a material impact on the Company.

Non-GAAP financial measures and additional subtotals in financial statements

Additional subtotal – adjusted funds flow from operations

Pipestone Energy uses "adjusted funds flow from operations" (cash from operating activities before changes in non-cash working capital and decommissioning provision costs incurred), a measure that is not defined under IFRS. Adjusted funds flow from operations should not be considered an alternative to, or more meaningful than, cash from operating activities, income (loss) or other measures determined in accordance with IFRS as an indicator of the Company's performance. Management uses adjusted funds flow from operations to analyze operating performance and leverage and believes it is a useful supplemental measure as it provides an indication of the funds generated by Pipestone Energy's principal business activities prior to consideration of changes in working capital.

The following table reconciles cash from operating activities to adjusted funds flow from operations:

($ thousands)	Three months ended December 31, 2019	2018	Year ended December 31, 2019	2018 [1]
	$	$	**$**	$
Cash from (used in) operating activities	**30,750**	(3,490)	**10,562**	(3,868)
Decommissioning provision costs incurred	**-**	-	**3**	-
Changes in non-cash working capital	**(14,142)**	(4,770)	**(7,777)**	(4,292)
Adjusted funds flow from (used in) operations	**16,608**	(8,260)	**2,788**	(8,160)

(1) IFRS 16, *Leases*, was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information was not restated. See "Critical Accounting Judgments, Estimates and Policies".

Funds flow from operations was included in the consolidated statement of cash flow in order to provide users with a better understanding of the key metrics utilized by Pipestone Energy to assess performance and how the calculation was arrived at. Accordingly, funds flow performance measures are not presented as non-GAAP measures in this MD&A.

Non-GAAP measures

This MD&A includes references to financial measures commonly used in the oil and natural gas industry. The terms "operating netback", "funds flow netback", "available funding", "adjusted working capital", "CROIC", "ROCE" are not defined under IFRS, which have been incorporated into Canadian GAAP, as set out in Part 1 of the Chartered Professional Accountants Canada Handbook – Accounting, are not separately defined under GAAP, and may not be comparable with similar measures presented by other companies.

Management believes the presentation of the non-GAAP measures provide useful information to investors and shareholders as the measures provide increased transparency and the opportunity to better analyze and compare performance against prior periods.

Operating netback and funds flow netback

Operating netback is calculated on a per-unit-of-production basis and is determined by deducting royalties, operating and transportation expenses from liquids and natural gas sales, after adjusting for realized commodity financial derivative instrument gains or losses.

Funds flow netback reflects funds flow on a per-unit-of-production basis and is determined by dividing funds flow by total production on a per-boe basis. Funds flow netback can also be determined by deducting G&A, transaction costs and cash financing expenses and adding financing income on a per-unit-of-production basis from the operating netback. Refer to "Financial and Operating Results" section above for further details.

Operating netback and funds flow netback are common metrics used in the oil and natural gas industry and are used by Company management to measure operating results on a per boe basis to better analyze and compare performance against prior periods, as well as formulate comparisons against peers.

Adjusted EBITDA and adjusted EBIT

Adjusted EBITDA is calculated as profit or loss before interest, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash and extraordinary items primarily relating to unrealized gains and losses on financial instruments. Adjusted EBITDA is used to calculate CROIC. Adjusted EBIT is calculated as adjusted EBITDA less depletion and depreciation. Adjusted EBIT is used to calculate ROCE. Also refer to "Liquidity and Capital Resources" above for further details.

CROIC and ROCE

CROIC is determined by dividing adjusted EBITDA by the gross carrying value of the Company's oil and gas assets at a point in time. For the purposes of the CROIC calculation, the net carrying value of the Company's exploration and evaluation assets, property and equipment and ROU assets, is taken from the Company's consolidated statement of financial position, and excludes accumulated depletion and depreciation as disclosed in the financial statement notes to determine the gross carrying value.

ROCE is determined by dividing adjusted EBIT by the carrying value of the Company's net assets. For the purposes for the ROCE calculation, net assets are defined as total assets on the Company's consolidated statement of financial position less current liabilities at a point in time.

CROIC and ROCE allow management and others to evaluate the Company's capital spending efficiency and ability to generate profitable returns by measuring profit or loss relative to the capital employed in the business. Also refer to "Liquidity and Capital Resources" above for additional information.

The Company has calculated its CROIC and ROCE using annualized results from the three months ended December 31, 2019 and balances as at December 31, 2019 as follows:

($ thousands)	Three months ended December 31, 2019
Net loss and comprehensive loss	13,143
Deferred income tax recovery	3,673
Financing expense	(8,919)
Financing income	267
Unrealized gain on interest rate risk management	846
Realized loss on interest rate risk management	(192)
D&D expense	(13,503)
E&E expense	(1,615)
Share-based compensation	(423)
Unrealized loss on commodity risk management	(14,282)
Adjusted EBITDA	21,005
Annualized Adjusted EBITDA	84,020

($ thousands)	As at December 31, 2019
Exploration and evaluation (E&E) assets – gross carrying value	38,881
Property and equipment (P&E) – net carrying value	518,199
P&E – accumulated D&D	17,056
E&E assets and P&E – gross carrying value	574,136
ROU assets – net carrying value	53,225
ROU assets – accumulated depreciation	1,531
E&E, P&E and ROU assets – gross carrying value	628,892
CROIC	**13.4%**

($ thousands)	Three months ended December 31, 2019
Adjusted EBITDA	21,005
D&D expense	(13,503)
Adjusted EBIT	7,502
Annualized Adjusted EBIT	30,008

($ thousands)	As at December 31, 2019
Total assets	663,816
Total current liabilities	65,437
Net assets	598,379
ROCE	**5.0%**

Adjusted working capital and available funding

Available funding is comprised of adjusted working capital and undrawn portions of the Company's Credit Facility. Adjusted working capital is comprised of current assets less current liabilities on the Company's consolidated statement of financial position and excludes the current portion of financial derivative instruments and lease liabilities. The available funding measure allows management and others to evaluate the Company's short-term liquidity. Also refer to "Liquidity and Capital Resources" above for additional information.

Basis of Barrel of Oil Equivalent

Petroleum and natural gas reserves and production volumes are stated as a "barrel of oil equivalent" (boe), derived by converting natural gas to oil equivalency in the ratio of 6,000 cubic feet of gas to one barrel of oil. Readers are cautioned that boe figures may be misleading, particularly if used in isolation. A boe conversion ratio of 6,000 cubic feet of gas to one barrel of oil is based on energy equivalency, which is primarily applicable at the burner tip, and does not represent a value equivalency at the wellhead.

Risk Factors

The acquisition, exploration and development of crude oil, condensate, other NGL and natural gas properties and the production, transportation and marketing of crude oil, condensate, other NGL and natural gas involves many risks, which may influence the ultimate success of the Company. While the management team of Pipestone Energy realizes these risks cannot be eliminated, it is are committed to monitoring and mitigating these risks. These risks include, but are not limited to the following:

- *Oil, condensate, other NGLs and natural gas prices are volatile. A sustained decline in oil, condensate, other NGLs and natural gas prices may adversely affect the Company's profitability;*
- *Declining general economic, business or industry conditions may have a material adverse effect on the Company's results of operations, liquidity and financial condition;*
- *The Company's actual capital costs, operating costs and economic returns may differ significantly from those it has anticipated;*
- *The Company's success depends on finding, developing or acquiring additional reserves, which requires significant capital investment. The Company may not be able to obtain needed capital or financing on satisfactory terms or at all;*
- *Negative public perception of oil sands development, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels, may harm the Company's profitability and corporate reputation;*
- *Federal and provincial legislative and regulatory initiatives regarding oil and natural gas development and fossil fuel activity could result in increased costs and additional operating restrictions or delays;*
- *Federal and provincial legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays;*
- *The Company relies on surface and groundwater licenses, which if rescinded or the conditions of which are amended, could disrupt its business and have a material adverse effect on its business;*
- *The Company may be unable to effectively manage growth;*
- *The Company's failure to successfully identify and make attractive acquisitions, joint ventures or investments, or successfully integrate future acquisitions of properties or businesses could disrupt its business, reduce its earnings and slow its growth;*
- *The unavailability, high cost or shortages of rigs, equipment, raw materials, supplies or qualified personnel may restrict the Company's operations;*
- *The direct and indirect costs of various GHG regulations, existing and proposed, may adversely affect the Company's business, operations and financial results, including demand for the Company's products;*
- *The Company may be unable to satisfy its obligations under its firm commitment transportation and processing arrangements;*
- *The Company relies on a few key employees whose absence or loss could disrupt its operations and have a material adverse effect on its business;*
- *The marketability of the Company's production is dependent upon compressors, gathering lines, pipelines, gas processing facilities and other facilities, certain of which the Company does not own*

nor control and which may fail or not perform as predicted. When these facilities are unavailable, the Company's operations can be interrupted and its revenues reduced;

- *The Company's identified drilling locations, which are part of the Company's anticipated future drilling plans, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling;*
- *Drilling for oil, condensate and other NGLs and natural gas, successfully stimulating well productivity and producing oil, condensate and other NGLs and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment and adversely affect the Company's business, financial condition or results of operations;*
- *Operating hazards and uninsured risks may result in substantial losses and could prevent the Company from realizing profits;*
- *The Company's drilling activities will encounter Sour Gas;*
- *The Company is exposed to project risks in the execution of its business plan;*
- *Unless the Company replaces the reserves that it produces through exploration and development, its existing reserves and production will decline, which would adversely affect the Company's business financial condition and results of operations;*
- *All of the Company's properties are located in the Pipestone Montney region, making the Company vulnerable to risks associated with having its production concentrated in that area;*
- *Unforeseen title defects may result in a loss of entitlement to production and reserves;*
- *The Company's permits, licenses and mineral rights may be subject to challenges by Indigenous groups;*
- *Abandonment and reclamation costs are difficult to estimate reliably and the accrued liabilities in respect of such costs may not be sufficient;*
- *The Company's development and exploratory drilling efforts and its well operations may not be profitable or achieve the Company's targeted returns;*
- *Part of the Company's strategy involves exploratory drilling using the latest available horizontal drilling and completion techniques; therefore, the results of the Company's planned exploratory drilling activities are subject to drilling and completion technique risks and drilling results may not meet the Company's expectations for reserves or production;*
- *The Company has limited intellectual property protection for its operating practices and depends on the expertise of its employees and contractors;*
- *Third parties may make claims regarding the Company's rights to use the techniques and equipment the Company employs;*
- *Certain of the Company's undeveloped leasehold acreage is subject to agreements that may expire in the near future;*
- *Properties the Company has acquired and may acquire in the future may not produce as projected, and the Company may be unable to determine reserve potential, identify liabilities associated with the properties that the Company acquires or obtain protection from sellers against such liabilities;*
- *The Company's operations are subject to various governmental regulations which require compliance that can be burdensome and expensive;*
- *Provincial laws and regulations are a significant factor in the profitability of oil, condensate and other NGLs and natural gas production in Canada and changes to these regimes and/or in their interpretation and enforcement could adversely affect the Company's profitability;*
- *The Company's operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety concerns and requirements that are applicable to the Company's business activities;*
- *Restrictions on operational activities intended to protect certain species of wildlife may adversely affect the Company's ability to conduct drilling and other operational activities in some of the areas where it operates;*
- *Some of the Company's directors and officers have conflicts of interest as a result of their involvement with other firms or companies;*
- *Actual results may differ materially from management estimates and assumptions;*
- *The Company's activities are affected by seasonality;*

- *The Company may be affected by alternatives to and changing demand for petroleum products;*
- *The Company faces extensive competition in its industry;*
- *The Company may be exposed to third-party credit risk;*
- *The Company depends upon a limited number of customers for the sale of most of its oil, condensate and other NGLs and natural gas production. The loss of one or more of these purchasers or the security of such purchase contracts could have a material adverse effect on the Company's business and financial condition;*
- *Lower oil, condensate and other NGLs and natural gas prices and higher costs increase the risk of write-downs of the Company's oil and natural gas property assets;*
- *The Company's use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of the Company's drilling operations;*
- *The Company has entered into commodity price hedging instruments and may in the future enter into additional contracts for a portion of its production, which may result in the Company making cash payments or prevent the Company from receiving the full benefit of increases in prices for oil, condensate and other NGLs and natural gas;*
- *A terrorist attack or armed conflict could harm the Company's business;*
- *The Company's information assets and critical infrastructure may be subject to cyber security risks;*
- *Loss of the Company's information and computer systems could adversely affect the Company's business;*
- *The Company may be unable to dispose of non-strategic assets on attractive terms and may be required to retain liabilities for certain matters;*
- *The Company may be required to make a security deposit under provincial liability management programs;*
- *Reassessment of the Company's prior transactions and tax filings could subject the Company to higher than expected past or future tax liability, interest or penalties. Changes to tax laws, or the interpretation thereof, may have a detrimental effect on the Company;*
- *Variations in foreign exchange rates and interest rates could negatively impact the Company's production revenues, the value of the Company's reserves and the Company's cost of debt;*
- *The Company's insurance policies may not be sufficient to cover the full extent of the risks to which the Company is exposed;*
- *The Company may become involved in litigation which could have a material adverse effect on the Company's business and financial condition;*
- *Non-IFRS measures are based upon variable components and future calculations may vary;*
- *Breach by a third-party of its obligations to the Company could have a material adverse effect on the Company's business and financial condition;*
- *Future expansion by the Company into new activities may change the Company's risk exposure;*
- *The Company may not be able to respond quickly to competitive pressures to adopt new technologies which could have a materially adverse effect on the Company's business and financial condition;*
- *Estimates of oil, NGLs and natural gas reserves and production therefrom are uncertain and may vary substantially from actual production;*
- *Significant Shareholder Control of the Company;*
- *The price of the Common Shares could be volatile;*
- *There may be no return on investment in the Common Shares;*
- *The Common Shares may be subject to further dilution and a significant number of Common Shares may be sold by shareholders;*
- *The Company has no near-term plans to pay dividends;*
- *The Company may be unable to comply with its covenants under the credit agreement or otherwise default on its obligations under the credit agreement;*
- *The Company may incur substantially more indebtedness, which could exacerbate the risks that the Company faces; and*

- *Restrictive covenants in the credit agreement, and in future debt instruments may restrict the Company's ability to pursue its business strategies.*

Forward-Looking Statements

This document contains certain forward-looking statements. Forward-looking statements are subject to known and unknown risks, uncertainties and other factors that could influence actual results or events and cause them to differ materially from those stated, anticipated or implied. Forward-looking statements necessarily involve risks including, without limitation, those associated with liquids and natural gas exploration, development, production, marketing and transportation, such as dry holes and non-commercial wells, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, production declines, health, safety and environmental risks, competition from other producers and the ability to access sufficient capital from internal and external sources. Forward-looking information may include statements with words such as “anticipate”, “believe”, “expect”, “plan”, “intend”, “estimate”, “propose”, “project”, “scheduled”, or similar words suggesting future outcomes. Readers and prospective investors in the Company’s securities are cautioned not to place undue reliance on forward-looking information as, by its nature, it is based on current expectations regarding future events that involve a number of assumptions, inherent risks and uncertainties, which could cause actual results to differ materially from those anticipated by the Company.

In particular, but without limiting the foregoing, this document contains forward-looking statements pertaining to: the Company’s plans to be fully funded to achieve a sustainable business capable of generating free cashflow above its maintenance requirements in a flat US$40 per barrel WTI and C$1.75 per GJ commodity price environment; 2020 guidance including full year production estimates, exit production estimates and capital expenditures; the Company’s 2020 development plans and the timing and occurrence or non-occurrence thereof all plans; plans to bring on production from 12 new wells on 2 pads; timing to bring Pipestone Energy’s second pad at 6-30 on-stream; drilling and completion plans on Pipestone Energy’s 6-24 pad and plans to then suspend drilling; the Company’s 2020 outlook including the Company being well positioned to deliver a combination of attractive year-over-year production growth while generating robust returns on capital employed and maintaining a solid balance sheet; 2020 development expenditures being concentrated around the most condensate-rich results realized to date and weighted 85 percent to half-cycle DCE&T expenditures; the Company filling its installed in-field infrastructure capacity of 33,000 boe per day over the next two year; the Company experiencing better run-times and production volumes at third-party processing facilities in 2020; Pipestone Energy being able to reduce its per boe costs in 2020 with respect to operating, transportation and G&A expense categories; and financial liabilities and commitments and expected increases in operating cash through production increases.

With respect to the forward-looking statements contained in this document, Pipestone Energy has assessed material factors and made assumptions regarding, among other things: future commodity prices and currency exchange rates, including consistency of future oil, natural gas liquids (NGLs) and natural gas prices with current commodity price forecasts; the ability to integrate Blackbird’s and Predecessor Pipestone’s historical businesses and operations and realize financial, operational and other synergies from the combination transaction completed on January 4, 2019; Pipestone Energy’s continued ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the predictability of future results based on past and current experience; the predictability and consistency of the legislative and regulatory regime governing royalties, taxes, environmental matters and oil and gas operations, both provincially and federally; Pipestone Energy’s ability to successfully market its production of oil, NGLs and natural gas; the timing and success of drilling and completion activities (and the extent to which the results thereof meet expectations); Pipestone Energy’s future production levels and amount of future capital investment, and their consistency with Pipestone Energy’s current development plans and budget; future capital expenditure requirements and the sufficiency thereof to achieve Pipestone Energy’s objectives; the successful application of drilling and completion technology and processes; the applicability of new technologies for recovery and production of Pipestone Energy’s reserves and other resources, and their ability to improve capital and operational efficiencies in the future; the recoverability of Pipestone Energy's reserves and other resources; Pipestone Energy’s ability to economically produce oil and gas from its properties and the timing and cost to do so; the performance of both new and existing wells; future cash flows from production; future sources of funding for Pipestone Energy’s capital program, and its ability to obtain external financing when required and on acceptable terms; future debt levels;

geological and engineering estimates in respect of Pipestone Energy's reserves and other resources; the accuracy of geological and geophysical data and the interpretation thereof; the geography of the areas in which Pipestone Energy conducts exploration and development activities; the timely receipt of required regulatory approvals; the access, economic, regulatory and physical limitations to which Pipestone Energy may be subject from time to time; and the impact of industry competition.

The forward-looking statements contained herein reflect management's current views, but the assessments and assumptions upon which they are based may prove to be incorrect. Although Pipestone Energy believes that its underlying assessments and assumptions are reasonable based on currently available information, undue reliance should not be placed on forward-looking statements, which are inherently uncertain, depend upon the accuracy of such assessments and assumptions, and are subject to known and unknown risks, uncertainties and other factors, both general and specific, many of which are beyond Pipestone Energy's control, that may cause actual results or events to differ materially from those indicated or suggested in the forward-looking statements. Such risks and uncertainties include, but are not limited to, volatility in market prices and demand for oil, NGLs and natural gas and hedging activities related thereto; the ability to successfully integrate Blackbird's and Predecessor Pipestone's historical businesses and operations; general economic, business and industry conditions; variance of Pipestone Energy's actual capital costs, operating costs and economic returns from those anticipated; the ability to find, develop or acquire additional reserves and the availability of the capital or financing necessary to do so on satisfactory terms; and risks related to the exploration, development and production of oil and natural gas reserves and resources. Additional risks, uncertainties and other factors are discussed in Pipestone Energy's annual information form dated March 12, 2020, a copy of which is available electronically on SEDAR at www.sedar.com.

The forward-looking statements contained in this document are made as of the date hereof and Pipestone Energy assumes no obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, unless required by applicable securities laws. All forward-looking statements herein are expressly qualified by this advisory.

Abbreviations

The following summarizes the abbreviations used in this document:

Condensate and Crude Oil, and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
bbls/d	barrels per day	Mcf/d	thousand cubic feet per day
boe	barrel of oil equivalent	GJ	Gigajoule; 1 Mcf of natural gas is about 1.05 GJ
Mboe	thousand barrels of oil equivalent	MMBtu	million British thermal units; 1 GJ is about 0.95 MMBtu
boe/d	barrel of oil equivalent per day		
NGL	natural gas liquids, consisting of ethane (C_2), propane (C_3) and butane (C_4)		
Bbls/MMcf	barrels per million cubic feet		
CGR	Condensate-gas ratio. Measures the liquid content of the hydrocarbon mixture		
condensate	Pentanes plus (C_5+) separated at the field level and C_5+ separated from the NGL mix at the facility level		

Other Abbreviations	
$000s	thousands of dollars
Adjusted working capital	working capital (current assets less current liabilities), excluding financial derivative instruments and lease liabilities
AECO	the AECO Hub, a natural gas storage facility located in Suffield and Countess, Alberta, part of the NOVA Pipeline System
Alliance Chicago Exchange Hub	a market hub for natural gas transported on the Alliance Pipeline to be purchased and sold between entities
Alliance Pipeline	a natural gas pipeline running from northeastern British Columbia to Illinois, in the United States
C$	Canadian dollars
Chicago City	Chicago Index Futures natural gas price

Other Abbreviations	
Gate	
CNOR LP	Canadian Non-Operated Resources LP
collar	a risk-management strategy employed by the Company in which an out-of-the-money put option is purchased, while simultaneously writing an out-of-the-money call option. Collars are entered into at no cost (the cost of the put is offset by the proceeds of the call). Collars allow the Company to receive the price of the commodity between the collar range. The downside price protection is at the cost of limiting the potential upside price
CROIC	cash return on invested capital
D&D	depletion and depreciation
EBIT	earnings before interest and taxes
EBITDA	earnings before interest, taxes, depreciation and amortization
EdCon	Edmonton Condensate
Enbridge	Enbridge Inc. and its affiliates
G&A	general and administrative
GAAP	Generally accepted accounting principles
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRIC	International Financial Reporting Interpretations Committee
IFRS	International Financial Reporting Standards
IFRS 16	International Financial Reporting Standards 16, *Leases*
Keyera	Keyera Corp. and its affiliates
LNG	liquified natural gas
NE	Northeast
NGTL	Nova Gas Transmission Ltd. Refers to a natural gas gathering system for the Western Canadian Sedimentary Basin
NMN	Not meaningful number
NW	Northwest
NYMEX	New York Mercantile Exchange
Pembina	Pembina Pipeline Corporation and its affiliates
PSU	performance share unit
Q1	first quarter ended March 31st
Q2	second quarter ended June 30th
Q3	third quarter ended September 30th
Q4	fourth quarter ended December 31st
ROCE	return on capital employed
ROU	right-of-use
RSU	restricted share unit
SE	Southeast
SW	Southwest
swap	over-the-counter contracts relating to interest rates, foreign exchange, or commodities. Entered into by the Company to reduce variability and manage risk via fixing that variable
TCPL	TC Pipelines Limited
Tidewater	Tidewater Midstream and Infrastructure Ltd. and its affiliates
TSX	Toronto Stock Exchange
US$	United States dollars
WTI	West Texas Intermediate
XLE	extreme limited entry
YTD	year-to-date

Corporate Information

BOARD OF DIRECTORS

GORDON RITCHIE, CHAIR [(1)(2)]

GARTH BRAUN [(2)]

WILLIAM LANCASTER [(1)(3)]

JOHN ROSSALL [(1)(2)(3)]

GEETA SANKAPPANAVAR [(3)]

ROBERT TICHIO [(2)]

PAUL WANKLYN

Notes:

(1) Audit Committee
(2) Compensation and Governance Committee
(3) Reserves and HSE Committee

MANAGEMENT

PAUL WANKLYN
President & Chief Executive Officer

DUSTIN HOFFMAN
Chief Operating Officer

CRAIG NIEBOER
Chief Financial Officer

DARCY ERICKSON
Vice President, Operations & Production

DAN VAN KESSEL
Vice President, Corporate Development

NEAL ROSS
Corporate Secretary

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AUDITORS
KPMG LLP
Calgary, Alberta

BANKERS
National Bank of Canada
Bank of Montreal
ATB Financial
Canadian Western Bank

EVALUATION ENGINEERS
McDaniel & Associates Consultants Ltd.
Calgary, Alberta

LEGAL COUNSEL
Osler, Hoskin & Harcourt LLP
Calgary, Alberta

TRANSFER AGENT
Computershare Limited
Calgary, Alberta

STOCK EXCHANGE LISTING
TSX Venture Exchange
Symbol: PIPE