MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc.'s ("Perpetual", the "Company" or the "Corporation") operating and financial results for the year ended December 31, 2019 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes for the years ended December 31, 2019 and 2018. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). The Corporation adopted IFRS 16, "Leases" ("IFRS 16"), effective January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section of this MD&A for further information. Readers are referred to the advisories for additional information regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information and Statements" section of this MD&A. The date of this MD&A is March 18, 2020.

NATURE OF BUSINESS: Perpetual is an oil and natural gas exploration, production and marketing company headquartered in Calgary, Alberta. Perpetual operates a diversified asset portfolio, including liquids-rich natural gas assets in the deep basin of West Central Alberta, heavy oil and shallow natural gas in Eastern Alberta, and undeveloped oil sands leases in Northern Alberta. Additional information on Perpetual, including the most recently filed Annual Information Form ("AIF"), can be accessed at www.sedar.com or from the Corporation's website at www.perpetualenergyinc.com.

ADVISORIES

NON-GAAP MEASURES: The terms "adjusted funds flow", "adjusted funds flow per share", "adjusted funds flow per boe", "available liquidity", "cash costs", "gas over bitumen revenue, net of payments", "net working capital deficiency (surplus)", "net debt", "net bank debt", "net debt to adjusted funds flow ratio", "operating netback", "realized revenue", and "enterprise value" used in this MD&A are not recognized under GAAP. Management believes that in addition to net income (loss) and net cash flows from (used in) operating activities as defined by GAAP, these terms are useful supplemental measures to evaluate performance. Users are cautioned however that these measures should not be construed as an alternative to net income (loss) or net cash flows from (used in) operating activities determined in accordance with GAAP as an indication of Perpetual's performance, and may not be comparable with the calculation of similar measurements by other entities.

Adjusted funds flow: Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations and meet its financial obligations. Adjusted funds flow is calculated based on cash flows from (used in) operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations since Perpetual believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. The Company has also deducted payments of the gas over bitumen royalty financing from adjusted funds flow to present these payments net of gas over bitumen royalty credits received. These payments are indexed to gas over bitumen royalty credits and are recorded as a reduction to the Corporation's gas over bitumen royalty financing obligation in accordance with IFRS. Additionally, the Company has excluded payments of restructuring costs associated with employee downsizing costs, which management considers to not be related to cash flow from operating activities.

Adjusted funds flow per share is calculated using the same weighted average number of shares outstanding used in calculating net income (loss) per share. Adjusted funds flow is not intended to represent net cash flows from (used in) operating activities calculated in accordance with IFRS.

Adjusted funds flow per boe is calculated as adjusted funds flow divided by total production sold in the period.

The following table reconciles net cash flows from (used in) operating activities to adjusted funds flow:

	Three months ended December 31,		Years ended December 31,	
($ thousands, except per share and per boe amounts)	**2019**	2018	**2019**	2018
Net cash flows from (used in) operating activities	**(1,290)**	5,163	**17,806**	31,525
Change in non-cash working capital	**705**	2,284	**(4,602)**	(2,541)
Decommissioning obligations settled	**540**	811	**1,733**	1,969
Payments of gas over bitumen royalty financing	**(225)**	(257)	**(1,013)**	(1,135)
Payments of restructuring costs	**610**	51	**610**	337
Adjusted funds flow	**340**	8,052	**14,534**	30,155
Adjusted funds flow per share	**0.01**	0.13	**0.24**	0.50
Adjusted funds flow per boe	**0.46**	9.22	**4.43**	7.80

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach, resulting in an increase in net cash flows from operating activities and adjusted funds flow of $0.2 million for the year ended December 31, 2019. Comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

Available Liquidity: Available Liquidity is defined as Perpetual's reserve-based credit facility borrowing limit (the "Borrowing Limit"), plus the fair value of the Tourmaline Oil Corp. ("TOU") share investment, less borrowings and letters of credit issued under the reserve-based credit facility (the "Credit Facility") and the TOU share margin demand loan. Management uses available liquidity to assess the ability of the Company to finance capital expenditures and expenditures on decommissioning obligations, and to meet its financial obligations.

Cash costs: Cash costs are comprised of royalties, production and operating, transportation, general and administrative, and cash finance expense. Cash costs per boe is calculated by dividing cash costs by total production sold in the period. Management believes that cash costs assist management and investors in assessing Perpetual's efficiency and overall cost structure.

	Three months ended December 31,		Years ended December 31,	
($ thousands, except per boe amounts)	**2019**	2018	**2019**	2018
Royalties	**3,383**	2,283	**11,260**	10,594
Production and operating	**3,839**	4,851	**18,332**	19,229
Transportation	**1,551**	1,489	**6,258**	6,068
General and administrative	**2,406**	3,793	**11,660**	13,630
Cash finance expense	**2,376**	2,242	**9,280**	8,707
Cash costs	**13,555**	14,658	**56,790**	58,228
Cash costs per boe	**18.44**	16.79	**17.31**	15.06

Realized revenue: Realized revenue is the sum of realized natural gas revenue, realized oil revenue and realized natural gas liquids ("NGL") revenue which includes realized gains (losses) on financial natural gas, crude oil, NGL and foreign exchange contracts but excludes any realized losses resulting from marketing contracts associated with the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition") to Sequoia Resources Corp. ("Sequoia"). Realized revenue, including foreign exchange and the market diversification contract, is used by management to calculate the Corporation's net realized commodity prices, taking into account monthly settlements of financial crude oil and natural gas forward sales, collars, basis differentials, and forward foreign exchange sales. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices and foreign exchange rates. Any related realized gains or losses are considered part of the Corporation's realized commodity price.

Gas over bitumen revenue, net of payments: Gas over bitumen revenue, net of payments, includes gas over bitumen royalty credits less monthly payments of the gas over bitumen royalty financing. This is used by management to calculate the Corporation's net realized gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty credits.

Operating netback: Operating netback is calculated by deducting royalties, production and operating expenses, and transportation costs from realized revenue. Operating netback is also calculated on a per boe basis using production sold for the period. Operating netback on a per boe basis can vary significantly for each of the Company's operating areas. Perpetual considers operating netback to be an important performance measure as it demonstrates its profitability relative to current commodity prices.

Net working capital deficiency (surplus): Net working capital deficiency (surplus) includes total current assets and current liabilities excluding short-term derivative assets and liabilities related to the Corporation's risk management activities, TOU share investment, TOU share margin demand loan, revolving bank debt, current portion of gas over bitumen royalty financing, current portion of lease liabilities, and current portion of provisions.

Net bank debt, net debt, and net debt to adjusted funds flow ratio: Net bank debt is measured as current and long-term revolving bank debt including net working capital deficiency (surplus). Net debt includes the carrying value of net bank debt, the principal amount of the term loan, the principal amount of the TOU share margin demand loan and the principal amount of senior notes, reduced for the fair value of the TOU share investment. Net debt, net bank debt, and net debt to adjusted funds flow ratios are used by management to assess the Corporation's overall debt position and borrowing capacity. Net debt to adjusted funds flow ratios are calculated on a trailing twelve-month basis.

Enterprise value: Enterprise value is equal to net debt plus the market value of issued equity, and is used by management to analyze leverage. Enterprise value is not intended to represent the total funds from equity and debt received by the Corporation upon issuance.

VOLUME CONVERSIONS: Barrel of oil equivalent ("boe") may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a conversion ratio for natural gas of 6 Mcf:1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In addition, utilizing a conversion on a 6 Mcf:1 bbl basis may be misleading as an indicator of value as the value ratio between natural gas and crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl.

FOURTH QUARTER 2019 HIGHLIGHTS

Fourth quarter exploration and development expenditures of $2.0 million were directed towards the Eastern Alberta core area, and included initial costs to drill two (2.0 net) heavy oil wells targeting the Clearwater formation at Ukalta that were spud in late December. These two wells were brought on production in late January, with an additional two (2.0 net) wells drilled, completed, and put on production in late-February. Exploration and development expenditures also included funds to acquire additional undeveloped crown lands focused on the Clearwater play in its Eastern Alberta core area.

Production averaged 7,991 boe/d in the fourth quarter, down 16% from the prior year period due to lower natural gas and NGL production which resulted from the deferral of gas-focused capital spending in response to continued low natural gas prices. Compared to the prior year period, production was also impacted by the shut-in of 1.8 MMcf/d (300 boe/d) of production at the Company's Panny property in Eastern Alberta in the third quarter of 2019. Perpetual expects this production to remain offline indefinitely, or until excessive property tax assessments are reduced.

Realized revenue was $14.3 million in the fourth quarter, down 37% from the prior year period, due to a 16% decrease in production combined with a 25% decrease in realized revenue per boe related to lower NYMEX natural gas prices and hedging losses. Decreased realized pricing in the fourth quarter of 2019 reflected realized losses on derivatives of $1.5 million, compared to realized gains of $1.3 million in the prior year period. In addition, the market diversification contract eroded natural gas revenue by $0.2 million during the fourth quarter due to the relative increase in AECO Daily Index Prices compared to NYMEX. AECO prices strengthened during the fourth quarter in response to changes made to TC Energy's NGTL natural gas pipeline maintenance operating protocols that were implemented in early October. In anticipation of tightening basis differentials, Perpetual modified its 40,000 MMBtu/d market diversification contract in late September to shift its pricing back to AECO for the December 2019 to October 2020 period. Realized heavy oil and NGL prices improved significantly over the prior year, increasing 121% and 23% respectively from fourth quarter 2018 prices. The increase in realized oil prices was due to the substantial narrowing of the WCS differential to US$15.83/bbl from US$39.42/bbl in the fourth quarter of 2018, which far outweighed the 3% decrease in WTI benchmark pricing over the same period.

Cash costs were $13.6 million in the fourth quarter, a decrease of $1.1 million (8%) from the prior year period due primarily to a $1.4 million reduction in general and administrative costs compared to the prior year period, resulting from the reduction of approximately 25% of Perpetual's corporate employee head count, combined with a reduction in compensation for remaining employees that was implemented at the end of the third quarter.

The net loss for the fourth quarter of 2019 was $32.5 million ($0.54/share) compared to $0.3 million ($0.01/share) in the prior year period. The increase in net loss was due primarily to impairment charges of $24.5 million recognized during the fourth quarter of 2019, combined with unrealized losses on derivatives of $3.4 million (Q4 2018 – unrealized gains of $10.9 million) associated with the tightening of the basis differential between NYMEX natural gas futures prices and AECO futures prices in the fourth quarter, partially offset by an unrealized gain on the Tourmaline Oil Corp. ("TOU") share investment of $3.2 million (Q4 2018 – unrealized loss of $9.5 million).

Net cash flows used in operating activities were $1.3 million, compared to $5.2 million of cash flows from operating activities in the prior year period. The decrease was due to the 16% decrease in production combined with realized natural gas prices which were 54% lower than the prior year.

Adjusted funds flow for the fourth quarter of 2019 was $0.3 million ($0.01/share), down 96% from $8.1 million ($0.13/share) in the prior year period, due to the decrease in production combined with significantly lower realized natural gas prices caused by the change in basis differentials between NYMEX and AECO based markets.

In December 2019, Perpetual sold 656,773 TOU shares at a weighted average price of $14.78 per share and used the proceeds of $9.7 million to partially repay the TOU share margin demand loan. In January 2020, the Company sold its remaining 1,000,000 TOU shares for net cash proceeds of $14.3 million. Net proceeds were used to fully repay the TOU share margin demand loan and to repay a portion of the Credit Facility.

2019 ANNUAL HIGHLIGHTS

Perpetual's 2019 capital program was funded from adjusted funds flow, with investment weighted to heavy oil drilling in Eastern Alberta. Exploration and development capital spending of $12.9 million (2018 – $26.5 million), resulted in finding and development costs ("F&D") of $10.54/boe (2018 – $5.09/boe) on a proved and probable basis, including changes in future development capital ("FDC"). Combined with an operating netback of $11.50/boe (2018 – $13.79/boe), Perpetual achieved an F&D recycle ratio of 1.1 times (2018 F&D recycle ratio – 2.7 times). The Company added proved plus probable reserves of 2.4 million boe to replace 74% of 2019 production. In 2018, the Company added proved plus probable reserves of 5.2 million boe to replace 134% of 2018 production.

Production in 2019 averaged 8,988 boe/d (22% oil and NGL), a decrease of 15% from 10,594 boe/d (17% oil and NGL) in 2018. Production peaked during the first quarter of 2019 and then declined for the remainder of the year, as drilling activity at East Edson was deferred pending higher natural gas prices. The Company drilled five (5.0 net) wells targeting heavy oil in Eastern Alberta, including two (2.0 net) horizontal multi-lateral wells to delineate new reserves in the Clearwater formation at Ukalta. These wells, combined with the four (4.0 net) new first quarter 2020 horizontal multi-lateral drills, are producing heavy oil at a combined rate of 730 bbl/d from Ukalta.

Realized revenue was $73.6 million in 2019, down 18% from $89.2 million in 2018 due primarily to the 15% decrease in annual production. Realized revenue was also negatively impacted by realized losses on derivatives of $0.8 million (2018 – realized gains of $3.1 million). Market diversification contract natural gas sales contributed an incremental $0.64/Mcf over the AECO Daily Index average price in 2019 (2018 – $1.02/Mcf).

Cash costs were $56.8 million in 2019, down $1.4 million (2%) from 2018 cash costs due primarily to the reduction in general and administrative costs implemented at the end of the third quarter. Production and operating expenses also decreased by 5% over the prior year, due to the absence of $1.0 million in remediation and water hauling costs from the Mannville produced water spill which occurred in the third quarter of 2018.

The net loss for 2019 was $94.0 million ($1.56/share), up from $20.4 million in 2018 ($0.34/share). The net loss was negatively impacted by the $21.9 million unrealized loss on derivatives (2018 – unrealized gain of $5.7 million) in addition to impairment losses of $47.1 million which were recognized in 2019 (2018 - $7.2 million), reflecting the decrease in forward natural gas and NGL pricing during 2019. An unrealized loss of $3.2 million recognized in 2019 related to the change in fair value of the TOU share investment (2018 – $9.6 million) also contributed to the net loss.

For the year ended December 31, 2019, net cash flow from operating activities was $17.8 million compared to $31.5 million in 2018. The decrease was driven by the 15% decrease in production and lower realized natural gas prices, despite the increased weighting of higher value oil and NGL in the production mix. Realized revenue of $22.43/boe was only 3% lower than the prior year (2018 – $23.07/boe). The increase in unrealized losses on derivatives and impairment losses in 2019 did not impact cash flow from operating activities.

For the year ended December 31, 2019, adjusted funds flow was $14.5 million ($0.24/share), down $15.6 million (52%) from $30.2 million ($0.50/share) in 2018 as the impact of the 15% year-over-year decrease in production combined with lower natural gas and NGL prices outweighed the 2% decrease in cash costs and increased heavy oil production.

SEQUOIA LITIGATION UPDATE

On August 15, 2019, the Court of Queen's Bench (the "Court") delivered the oral decision related to the Statement of Claim filed against Perpetual and its President and Chief Executive Officer ("CEO") on August 3, 2018, and on January 13, 2020, the Court issued its written decision with respect to the Company's disposition of shallow gas assets in Eastern Alberta to an unrelated third party on October 1, 2016 (the "Sequoia Litigation"). The decision dismissed and struck all but one of the claims filed by PwC in its capacity as trustee (the "Trustee") in bankruptcy of Sequoia Resources Corp ("Sequoia"). The Court did not find that the test for summary dismissal relating to whether the transaction was an arm's length transfer for purposes of section 96(1) of the Bankruptcy and Insolvency Act (the "BIA") was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim can continue against Perpetual. On August 23, 2019, the Trustee filed a notice of appeal with the Court of Appeal of Alberta, contesting the entire August 15, 2019 oral decision, and on August 26, 2019, Perpetual and its CEO filed a similar notice of appeal contesting the BIA claim portion of the oral decision. The appeal proceedings are scheduled to be heard in December 2020.

On September 24, 2019, Perpetual filed an application for security for costs of the appeal. On January 28, 2020, the Court of Appeal issued its decision with respect to Perpetual's security for costs application, requiring the Trustee to post security with the Court of Appeal in the amount of $0.2 million prior to proceeding with its appeal. Applications have been filed by the Trustee to appeal the security for costs decision and alter the reasons for the decision. The Court of Appeal is scheduled to hear these applications in June 2020.

On February 25, 2020, Perpetual filed a new application to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the transaction nor caused to be insolvent by the transaction. The Court is scheduled to hear this application in June 2020.

Management expects that the Company is more likely than not to be successful in defending against the Sequoia litigation such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in Perpetual's financial statements.

FUTURE OPERATIONS

Perpetual has a first lien, reserve-based credit facility (the "Credit Facility"). On December 24, 2019, Perpetual's syndicate of lenders completed their semi-annual borrowing base redetermination, reducing the Credit Facility borrowing limit (the "Borrowing Limit") from $55 million to $45 million effective January 22, 2020. In January 2020, the Company sold its remaining 1,000,000 TOU shares for net cash proceeds of $14.3 million (the "TOU Share Proceeds"). Net proceeds were used to repay the TOU share margin demand loan with the balance used to repay a portion of the Credit Facility. The next Borrowing Limit redetermination is scheduled on or prior to March 31, 2020. If the Credit Facility repayment term is not extended at the next redetermination, all outstanding advances will become payable on November 30, 2020. The extension of the Credit Facility repayment term is dependent on the Company's ability to repay or extend the term of the $45 million second lien term loan that matures and requires repayment on March 14, 2021. The Company also has $33.6 million of unsecured senior notes that mature on January 23, 2022.

Perpetual had available liquidity at December 31, 2019 of $20.2 million, comprised of $5.1 million of available borrowings under the Credit Facility and the $15.2 million TOU share investment market value net of the associated $0.1 million TOU share margin demand loan. After giving pro forma effect to $45 million Borrowing Limit effective on January 22, 2020, and the TOU Share Proceeds, Perpetual had available liquidity at December 31, 2019 of $9.2 million.

Although the TOU Share Proceeds have reduced the Company's revolving bank debt borrowed under its Credit Facility, the Company remains dependent on the support of its lenders to the Credit Facility which has a current maturity of November 30, 2020. Further, the recent significant decline in natural gas and liquids prices has contributed to the Company projecting a significant reduction in cash flow from operating activities in 2020. The Company will require additional financing or will need to refinance the upcoming Credit Facility and term loan maturities as the available liquidity and operating cash flows are not anticipated to be sufficient. Perpetual is considering options including the sale or monetization of additional assets, the extension of existing debt maturity dates, or alternative financing.

However, due to the facts and circumstances detailed above coupled with considerable economic instability and uncertainty in the oil and gas markets which negatively impacts operating cash flows and lender and investor sentiment, there remains considerable risk around the Company's ability to address its liquidity shortfalls and upcoming maturities. In addition, there continues to be some uncertainty regarding the Statement of Claim which may restrict management's ability to manage its capital structure. As a result, there is a material uncertainty surrounding the Company's ability to continue as a going concern that creates significant doubt as to the ability of the Company to meets its obligations as they come due and, therefore, it may be unable to realize its assets and discharge its liabilities in the normal course of business.

These financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Corporation will be able to realize its assets and discharge its liabilities in the normal course of business. These financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern basis were not appropriate for these financial statements, then adjustments would be necessary in the carrying value of the assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

2020 GUIDANCE

The Company's Board of Directors approved a capital spending program of $6 million for the first quarter of 2020 to drill four (4.0 net) multi-lateral horizontal wells at Ukalta. Perpetual's reserve-based credit facility is currently undergoing its borrowing limit redetermination which is likely to reduce the current $45 million borrowing limit effective March 31, 2020 due to reductions in bank lending commodity price forecasts. Any reductions in the credit facility borrowing limit will reduce the Company's available liquidity. To preserve liquidity, the Company will defer further capital spending until the credit facility borrowing limit redetermination has been completed. The Company will issue its 2020 Guidance once the borrowing limit redetermination is known and capital spending plans have been determined.

2019 FOURTH QUARTER AND ANNUAL CAPITAL EXPENDITURES

($ thousands)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
Exploration and development	**1,983**	5,613	**12,865**	26,535
Corporate assets	**12**	4	**74**	353
Capital expenditures	**1,995**	5,617	**12,939**	26,888
Acquisitions	**–**	–	**–**	1,871
Proceeds from dispositions of oil and gas properties	**–**	(1,285)	**–**	(13,441)
Net capital expenditures	**1,995**	4,332	**12,939**	15,318

Exploration and development spending by area

($ thousands)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
West Central	**12**	4,235	**1,185**	13,665
Eastern	**1,971**	1,378	**11,680**	12,870
Total	**1,983**	5,613	**12,865**	26,535

Wells drilled by area

(gross/net)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
West Central	**–/–**	–/–	**–/–**	1/1.0
Eastern Alberta	**–/–**	–/–	**5/5.0**[(1)]	6/6.0
Total	**–/–**	–/–	**5/5.0**[(1)]	7/7.0

(1) Excludes the re-entry of one existing well bore at Mannville.

Perpetual's exploration and development spending in the fourth quarter of 2019 was $2.0 million, 18% higher than capital spending guidance provided with Perpetual's third quarter earnings release. Fourth quarter spending was focused in Eastern Alberta and included costs to acquire additional undeveloped crown lands focused on the Clearwater play, as well as initial costs to spud two (2.0 net) heavy oil wells targeting the Clearwater formation at Ukalta in late December. These two new wells were brought on production in late January. Two (2.0 net) additional step out wells at Ukalta were drilled and completed in the first quarter of 2020, and put on production in late-February. These four wells are currently producing at a combined rate of 540 bbl/d.

For the year ended December 31, 2019, exploration and development spending was $12.9 million, down 52% from 2018 as the 2019 program was purposefully managed to be funded from adjusted funds flow. The Company added proved plus probable reserves at an F&D cost, including changes in FDC of $10.54/boe. In addition, the Company added proved plus probable reserves of 2.4 million boe in 2019 to replace 74% of production. The Company added proved reserves at a F&D cost, including changes in FDC of $9.38/boe.

Spending in Eastern Alberta in 2019 was $11.7 million. At Mannville, three (3.0 net) horizontal wells were drilled in the second quarter of 2019, along with a re-entry to add two additional laterals to an existing oil well. At Ukalta, two (2.0 net) initial exploratory wells were drilled, completed and tied-in during the third quarter. The four (4.0 net) well winter drilling program was initiated late in the fourth quarter.

Spending in West Central in 2019 was $1.2 million, and was primarily directed towards the installation of field compression equipment and a sweetening tower to restore higher liquids ratio natural gas wells back to production.

Acquisitions and Dispositions

Proceeds (payments) on dispositions

($ thousands)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
Proceeds from dispositions of oil and gas properties	**–**	1,285	**–**	13,441
Payments on retained shallow gas marketing arrangements[(1)]	**–**	–	**–**	(8,540)
Net proceeds on dispositions	**–**	1,285	**–**	4,901

Gain (loss) on dispositions

($ thousands)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
Proceeds on dispositions of oil and gas properties	**–**	1,285	**–**	13,441
Carrying amount of PP&E disposed	**–**	–	**–**	(848)
Carrying amount of E&E disposed	**–**	(1,495)	**–**	(12,442)
Carrying amount of ARO disposed	**–**	120	**–**	500
Gain (loss) on disposition of oil and gas properties	**–**	(90)	**–**	651
Realized loss on retained shallow gas marketing arrangements[(1)]	**–**	–	**–**	(874)
Loss on dispositions	**–**	(90)	**–**	(223)

(1) Related to the Shallow Gas Disposition to Sequoia.

The Company did not complete any acquisitions or dispositions during the three months or year ended December 31, 2019. Net proceeds on dispositions were $1.3 million in the fourth quarter of 2018 and included the sale of the Company's Waskahigan area interests to a third party for cash consideration and a retained 1% gross overriding royalty on undeveloped lands to maintain exposure to future drilling conducted by the purchaser. For the year ended December 31, 2018, dispositions included the sale of non-core royalty interests and exploration and evaluation oil and gas properties for gross proceeds of $13.4 million and the transfer to the purchaser of $0.5 million in associated decommissioning obligations, resulting in a net gain of $0.7 million.

Expenditures on decommissioning obligations

During the three months ended December 31, 2019, Perpetual spent $0.5 million (Q4 2018 – $0.8 million) on abandonment and reclamation projects, consistent with previous guidance provided with Perpetual's third quarter earnings release. As part of Perpetual's focus on well and pipeline abandonment and reclamation, four reclamation certificates were received from the Alberta Energy Regulator ("AER") during the fourth quarter of 2019 (Q4 2018 – three reclamation certificates) which will result in the cessation of associated property tax and surface lease expenses. For the year ended December 31, 2019, Perpetual spent $1.7 million (2018 – $2.0 million) on abandonment and reclamation projects under the AER's area-based closure approach and has received 20 reclamation certificates to date (2018 – 18 reclamation certificates). Abandonment and reclamation expenditures of $1.5 million are forecast in 2020, focused in Mannville utilizing the area-based closure approach.

SUMMARY OF QUARTERLY AND ANNUAL NET LOSS

Three months ended December 31,		**2019**		2018
	(*$ thousands*)	**(*$/boe*)**	(*$ thousands*)	(*$/boe*)
Realized revenue[1]	**14,335**	**19.50**	22,797	26.11
Royalties	**(3,383)**	**(4.60)**	(2,283)	(2.61)
Production and operating expenses	**(3,839)**	**(5.22)**	(4,851)	(5.56)
Transportation costs	**(1,551)**	**(2.11)**	(1,489)	(1.71)
Operating netback[1]	**5,562**	**7.57**	14,174	16.23
Unrealized change in fair value of derivatives	**(3,369)**	**(4.58)**	10,885	12.47
Gas over bitumen royalty credit	**202**	**0.27**	302	0.35
Exploration and evaluation	**(811)**	**(1.10)**	(1,617)	(1.85)
General and administrative	**(2,406)**	**(3.27)**	(3,793)	(4.34)
Share-based payments	**(488)**	**(0.66)**	(566)	(0.65)
Depletion and depreciation	**(6,960)**	**(9.47)**	(7,777)	(8.91)
Loss on dispositions	**–**	**–**	(90)	(0.10)
Impairment	**(24,452)**	**(33.26)**	–	–
Finance expense	**(2,981)**	**(4.05)**	(2,306)	(2.64)
Change in fair value of TOU share investment	**3,205**	**4.36**	(9,543)	(10.93)
Net loss	**(32,498)**	**(44.19)**	(331)	(0.38)
Net loss per share - basic	**(0.54)**		(0.01)	

Years ended December 31,		**2019**		2018
	(*$ thousands*)	**(*$/boe*)**	(*$ thousands*)	(*$/boe*)
Realized revenue[1]	**73,572**	**22.43**	89,199	23.07
Royalties	**(11,260)**	**(3.43)**	(10,594)	(2.74)
Production and operating expenses	**(18,332)**	**(5.59)**	(19,229)	(4.97)
Transportation costs	**(6,258)**	**(1.91)**	(6,068)	(1.57)
Operating netback[1]	**37,722**	**11.50**	53,308	13.79
Unrealized change in fair value of derivatives	**(21,893)**	**(6.67)**	5,747	1.49
Gas over bitumen royalty credit	**852**	**0.26**	1,046	0.27
Exploration and evaluation	**(1,797)**	**(0.55)**	(2,212)	(0.57)
General and administrative	**(11,660)**	**(3.55)**	(13,630)	(3.52)
Share-based payments	**(2,295)**	**(0.70)**	(2,573)	(0.67)
Depletion and depreciation	**(31,188)**	**(9.51)**	(34,946)	(9.04)
Loss on dispositions	**–**	**–**	(223)	(0.06)
Impairment	**(47,052)**	**(14.34)**	(7,200)	(1.86)
Finance expense	**(11,951)**	**(3.64)**	(10,122)	(2.62)
Change in fair value of TOU share investment	**(3,207)**	**(0.98)**	(9,575)	(2.48)
Restructuring costs	**(1,546)**	**(0.47)**	–	–
Net loss	**(94,015)**	**(28.65)**	(20,380)	(5.27)
Net loss per share - basic	**(1.56)**		(0.34)	

(1) See "Non-GAAP measures" in this MD&A.

Operating Netbacks

The following table highlights Perpetual's operating netbacks for the three months and years ended December 31, 2019 and 2018:

	Three months ended December 31, 2019			Three months ended December 31, 2018		
(*$ thousands*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Petroleum and natural gas ("P&NG") revenue(1)	**9,366**	**6,464**	**15,830**	17,481	4,029	21,510
Realized gains (losses) on derivatives(2)	**–**	**–**	**(1,495)**	–	–	1,287
Royalties	**(2,584)**	**(799)**	**(3,383)**	(1,611)	(672)	(2,283)
Production and operating expenses(3)	**(1,698)**	**(2,141)**	**(3,839)**	(1,598)	(3,253)	(4,851)
Transportation costs	**(944)**	**(607)**	**(1,551)**	(1,085)	(404)	(1,489)
Operating netback	**4,140**	**2,917**	**5,562**	13,187	(300)	14,174

	Year ended December 31, 2019			Year ended December 31, 2018		
(*$ thousands*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Petroleum and natural gas revenue(1)	**47,199**	**27,162**	**74,361**	65,383	20,745	86,128
Realized gains (losses) on derivatives(2)	**–**	**–**	**(789)**	–	–	3,071
Royalties	**(7,833)**	**(3,427)**	**(11,260)**	(8,156)	(2,438)	(10,594)
Production and operating expenses(3)	**(7,188)**	**(11,144)**	**(18,332)**	(7,160)	(12,069)	(19,229)
Transportation costs	**(4,176)**	**(2,082)**	**(6,258)**	(4,616)	(1,452)	(6,068)
Operating netback	**28,002**	**10,509**	**37,722**	45,451	4,786	53,308

	Three months ended December 31, 2019			Three months ended December 31, 2018		
(*$/boe*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**6,253**	**1,738**	**7,991**	7,460	2,031	9,491
Petroleum and natural gas revenue(1)	**16.28**	**40.43**	**21.53**	25.47	21.56	24.63
Realized gains (losses) on derivatives(2)	**–**	**–**	**(2.03)**	–	–	1.48
Royalties	**(4.49)**	**(5.00)**	**(4.60)**	(2.35)	(3.60)	(2.61)
Production and operating expenses(3)	**(2.95)**	**(13.39)**	**(5.22)**	(2.33)	(17.40)	(5.56)
Transportation costs	**(1.64)**	**(3.80)**	**(2.11)**	(1.58)	(2.16)	(1.71)
Operating netback	**7.20**	**18.24**	**7.57**	19.21	(1.60)	16.23

	Year ended December 31, 2019			Year ended December 31, 2018		
(*$/boe*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**7,176**	**1,812**	**8,988**	8,737	1,857	10,594
Petroleum and natural gas revenue(1)	**18.02**	**41.06**	**22.67**	20.50	30.61	22.27
Realized gains (losses) on derivatives(2)	**–**	**–**	**(0.24)**	–	–	0.80
Royalties	**(2.99)**	**(5.18)**	**(3.43)**	(2.56)	(3.60)	(2.74)
Production and operating expenses(3)	**(2.74)**	**(16.84)**	**(5.59)**	(2.25)	(17.81)	(4.97)
Transportation costs	**(1.59)**	**(3.15)**	**(1.91)**	(1.45)	(2.14)	(1.57)
Operating netback	**10.70**	**15.89**	**11.50**	14.24	7.06	13.79

(1) Includes revenues related to the natural gas market diversification contract and physical forward sales contracts which settled during the period.
(2) Includes realized gains on financial derivatives and financial prompt month price optimization contracts. Realized gains and losses on financial derivatives are not allocated to the Company's core areas. Includes proceeds of $2.7 million ($0.17/Mcf) for the year ended December 31, 2019 received from the monetization of the Company's market diversification contract for the December 2019 to October 2020 period.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

For the fourth quarter of 2019, Perpetual's operating netback of $5.6 million ($7.57/boe) decreased 61% from $14.2 million ($16.23/boe) in the prior year period due to a 16% decrease in production combined with a 25% decrease in realized revenue per boe. Lower production was the result of natural declines at West Central, where capital expenditures were minimal in 2019 as a result of low natural gas prices. Lower realized revenue per boe was due to a 54% reduction in realized natural gas prices, reflecting weaker NYMEX natural gas prices compared to the fourth quarter of 2018, partially offset by higher realized oil and NGL prices. Canadian oil price differentials improved significantly in 2019 due to the implementation of production curtailments by the Government of Alberta. Perpetual's oil production is not subject to curtailment as its total production is below the designated curtailment production level.

For the year ended December 31, 2019, Perpetual's operating netback of $37.7 million ($11.50/boe) decreased 29% from $53.3 million ($13.79/boe) in 2018. The decrease in the 2019 operating netback was due to a 15% decline in production combined with the 17% decrease in operating netback per boe, which was the result of lower realized natural gas and NGL prices of 9% and 23% respectively and higher costs per boe.

Production

	Three months ended December 31,		Years ended December 31,	
	2019	2018	**2019**	2018
Natural gas (*MMcf/d*)				
Eastern Alberta	**2.8**	4.6	**3.6**	5.1
West Central	**33.8**	40.3	**38.7**	47.5
Total natural gas[1]	**36.6**	44.9	**42.3**	52.6
Crude oil (*bbl/d*)				
Eastern Alberta[2]	**1,264**	1,265	**1,216**	1,020
West Central	**11**	36	**8**	30
Total crude oil	**1,275**	1,301	**1,224**	1,050
Total NGL (*bbl/d*)[3]	**606**	715	**719**	774
Total production (*boe/d*)	**7,991**	9,491	**8,988**	10,594

(1) Natural gas production yields a heat content of 1.17 GJ/Mcf, resulting in higher realized natural gas prices on a $/Mcf basis. See "Commodity Prices".
(2) Primarily heavy oil.
(3) Primarily West Central liquids-rich gas.

Fourth quarter production averaged 7,991 boe/d (24% oil and NGL), down 1,500 boe/d or 16% from 9,491 boe/d in the prior year period (21% oil and NGL). Fourth quarter production was reduced by natural declines at East Edson in addition to the shut-in of 1.8 MMcf/d (300 boe/d) of production at the Company's Panny property in Eastern Alberta. This production was shut-in during the third quarter and Perpetual expects it to remain offline indefinitely, or until excessive property tax assessments are reduced. Fourth quarter production was at the low end of guidance provided with Perpetual's third quarter earnings release due to higher well maintenance downtime at the Mannville heavy oil operations.

Fourth quarter natural gas production averaged 33.8 MMcf/d at West Central, a decrease of 16% from the comparative period of 2018. The decrease was driven by natural declines resulting from limited capital investment during 2019 in response to low AECO natural gas prices.

West Central NGL yields were consistent with the fourth quarter of 2018 and previous quarters in 2019 at approximately 18 bbls per MMcf of natural gas produced.

Crude oil production in Eastern Alberta was consistent with the fourth quarter of 2018 at 1,264 bbl/d (Q4 2018 – 1,265 bbl/d). Production from the two (2.0 net) exploratory Clearwater formation multi-lateral horizontal wells at Ukalta combined to average 150 bbl/d in the fourth quarter of 2019.

For the year ended December 31, 2019, production decreased 15% to 8,988 boe/d (22% oil and NGL) compared to 10,594 boe/d (17% oil and NGL) in the prior year. Production peaked in the first quarter of 2019 and then declined for the remainder of the year, as drilling activity at East Edson was deferred pending higher natural gas prices.

During 2019, Perpetual shut-in an average 275 boe/d to take advantage of temporary situations when natural gas could be purchased at minimal cost to satisfy pre-sold volume commitments at attractive margins, resulting in realized revenue of $0.7 million ($0.05/Mcf) while retaining reserves for future production. Average annual natural gas production decreased 20% to 42.3 MMcf/d (2018 – 52.6 MMcf/d) and NGL production decreased 7% to 719 bbl/d (2018 – 774 bbl/d), reflecting the deferral of its liquids-rich natural gas drilling.

For the year ended December 31, 2019, crude oil production was 1,224 bbl/d, an increase of 17% from the prior year due to the drilling of three (3.0 net) new oil wells and a re-entry to add two additional laterals to an existing oil well at Mannville, combined with initial heavy oil production at Ukalta following the drilling, completion and tie-in of two (2.0 net) wells at the end of the third quarter. Perpetual has continued to focus on waterflood implementation and optimization from 2014 through 2019, with the positive impact of the waterflood evidenced by an overall reduction in decline rates at Mannville.

Commodity Prices

	Three months ended December 31,		Years ended December 31,	
	2019	2018	**2019**	2018
Reference prices				
NYMEX Daily Index (US*$/MMBtu*)	**2.50**	3.64	**2.63**	3.09
AECO Daily Index (*$/GJ*)	**2.35**	1.48	**1.67**	1.42
AECO Daily Index *($/Mcf)*(1)	**2.48**	1.56	**1.76**	1.50
Alberta Gas Reference Price (*$/GJ*)(2)	**2.01**	1.50	**1.40**	1.29
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**56.96**	58.81	**57.03**	64.77
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(15.83)**	(39.42)	**(12.76)**	(26.31)
WCS average (*Cdn$/bbl*)(3)	**54.29**	25.59	**58.88**	50.00
Average Perpetual prices				
Natural gas (*$/Mcf*)(1)				
AECO Daily Index	**2.48**	1.56	**1.76**	1.50
Heat Content Premium(4)	**0.27**	0.17	**0.19**	0.16
Market Diversification Contract	**(0.05)**	1.64	**0.64**	1.02
Realized gains (losses) on financial and physical gas derivatives(6)	**(0.56)**	0.84	**0.16**	0.26
Realized gains (losses) on prompt month price optimization	**(0.14)**	0.17	**0.02**	0.11
Realized natural gas price (*$/Mcf*)(5)	**2.00**	4.38	**2.77**	3.05
Percent of AECO Daily Index	**81%**	281%	**157%**	203%
Realized oil price (*$/bbl*)(5)	**43.85**	19.83	**44.87**	40.62
Realized natural gas liquids ("NGL") price (*$/bbl*) (5)	**43.93**	35.73	**41.01**	52.96

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.
(3) Derived internally using the Bank of Canada average foreign exchange rate of US$1.00 = Cdn$1.32 for the three months ended December 31, 2019 (Q4 2018 – $1.32) and $1.33 for the year ended December 31, 2019 (2018 – $1.30).
(4) Realized natural gas prices are at a premium to the AECO Daily Index due to higher average heat content of 1.17 GJ/Mcf. For the three months and year ended December 31, 2019, Perpetual received an 11% premium to the AECO Daily Index (three months and year ended December 31, 2018 – 11%) related to its higher average heat content.
(5) Realized natural gas, oil and NGL prices include physical forward sales contracts for which delivery was made during the reporting period and realized gains and losses on financial derivatives and foreign exchange contracts.
(6) Includes proceeds of $2.7 million ($0.17/Mcf) for the year ended December 31, 2019 received from the monetization of the Company's market diversification contract for the December 2019 to October 2020 period.

Despite US natural gas production growing by 7.3 Bcf/d from 2018 to 2019, increased demand from LNG exports from the US Gulf Coast and Northeast, as well as pipeline exports to Mexico, resulted in NYMEX natural gas prices decreasing by 15% from US$3.09/MMBtu in 2018 to an average of US$2.63/MMBtu in 2019. For the fourth quarter of 2019, NYMEX natural gas prices averaged US$2.50/MMBtu, down 31% from the prior year period as heating demand was reduced due to unseasonably warm temperatures experienced in the fourth quarter of 2019. In comparison, the AECO Daily Index price increased 18% from $1.42/GJ in 2018 to $1.67/GJ in 2019. In the fourth quarter of 2019, the Canadian Energy Regulator approved TC Energy's Temporary Service Protocol ("TSP") procedures for October 2019 and the April through October 2020 period. TSP prioritized interruptible delivery and storage transportation service over firm transportation receipt service on the NGTL system during maintenance restrictions. The result was a significant increase in AECO prices beginning October 2019.

Perpetual's realized natural gas price, including derivatives, decreased 54% to $2.00/Mcf in the fourth quarter of 2019 from $4.38/Mcf in the comparative period of 2018, and was only 81% of the AECO Daily Index price compared to 281% in the prior year period. The market diversification contract reduced the realized gas price by $0.05/Mcf (Q4 2018 – increase of $1.64/Mcf) on the relative weakness of NYMEX Daily Index prices compared to AECO during the quarter, while AECO-NYMEX basis hedging losses and prompt month optimization contracts reduced the realized gas price by a further $0.70/Mcf. Market diversification contract sales commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018, expiring October 31, 2024. Pricing is based on daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) until October 31, 2022 and three pricing hubs (Malin, Dawn and Emerson) from November 1, 2022 to October 31, 2024. These pricing hubs are located outside of Alberta and generally track North American NYMEX prices. During the fourth quarter of 2019, the average heat content conversion ratio for Perpetual's natural gas production was 1.17 GJ:1 Mcf, unchanged from the comparative period of 2018. Natural gas production from East Edson yields higher heat content gas compared to Perpetual's other production areas.

For the year ended December 31, 2019, Perpetual's realized natural gas price was $2.77/Mcf, down 9% from $3.05/Mcf in 2018. Perpetual's realized natural gas price in 2019 was 57% ($1.01/Mcf) higher than the AECO Daily Index price compared to a 103% ($1.55/Mcf) premium realized in 2018. The market diversification contract added $0.64/Mcf (2018 – $1.02/Mcf) on the relative strength of daily index prices at the five downstream markets compared to the AECO Daily Index. In response to TC Energy's changes to TSP maintenance operating protocols that were implemented early in the fourth quarter, Perpetual modified its market diversification contract to shift the pricing point back to AECO for the December 2019 to October 2020 period, and recorded a realized gain of $2.7 million ($0.17/Mcf).

WTI light oil prices decreased by 12% from US$64.77/bbl in 2018 to US$57.03/bbl in 2019 due to a number of factors. Bullish factors including the re-established Iranian supply restrictions implemented by the US; drone strikes on Saudi Arabian oil infrastructure in September 2019; agreement on Phase 1 of a trade deal with China; and escalation of geopolitical tensions between the US and Iran in December 2019, were not enough to fully counter the bearish factors which included gradual increases in global oil production and inventories during 2019; worries about a lengthy trade war between the US and China; and OPEC spare production capacity due to the continued supply restrictions implemented by OPEC.

Perpetual's realized oil price for the fourth quarter of 2019 was $43.85/bbl, 121% higher than the fourth quarter of 2018 despite realized losses on crude oil derivative contracts of $0.7 million ($6.18/bbl). Realized prices in the fourth quarter of 2018 were reduced by $0.44/bbl associated with realized hedging losses in the period. The increase in realized prices was due to the substantial narrowing of the WCS differential to US$15.83/bbl from US$39.42/bbl in the fourth quarter of 2018, which far outweighed the 3% decrease in WTI benchmark pricing over the same period. In early 2019, WCS differentials narrowed significantly due to increased crude by rail transport volumes and the implementation of temporary oil production restrictions by the Government of Alberta which reduced storage volumes and alleviated oil pipeline capacity issues. The volume restrictions were significantly reduced over the course of 2019 as Western Canadian storage levels decreased and differentials stabilized.

For the year ended December 31, 2019, Perpetual's realized oil price was $44.87/bbl, up 10% from $40.62/bbl in 2018. The increase was due to the narrowing of the WCS differential to US$12.76/bbl (2018 – US$26.31/bbl) which more than exceeded the 12% decrease (US$7.74/bbl) in WTI light oil prices. Realized oil prices were reduced by $8.74/bbl associated with realized hedging losses during the year (2018 – realized hedging losses of $2.16/bbl).

Perpetual's realized NGL price for the fourth quarter of 2019 was $43.93/bbl, up 23% from the fourth quarter of 2018, reflecting an increase in all NGL component prices relative to Cdn$ WTI as delays in starting up the North Montney natural gas pipeline reduced anticipated NGL supply, thereby improving prices. Perpetual's average NGL sales composition for the fourth quarter of 2019 improved to 64% condensate compared to 58% in the prior year period.

For the year ended December 31, 2019, Perpetual's realized NGL price was $41.01/bbl, down 23% from $52.96/bbl in 2018, correlating with the 12% decrease in WTI prices over the same period. Approximately 63% of Perpetual's NGL production is comprised of condensate (2018 – 60%) which typically tracks light oil prices.

Revenue

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Petroleum and natural gas revenue				
Natural gas[1]	**7,263**	16,734	**39,318**	54,769
Oil[1]	**5,867**	2,427	**23,958**	16,390
NGL	**2,700**	2,349	**11,085**	14,969
Petroleum and natural gas revenue	**15,830**	21,510	**74,361**	86,128
Realized gains (losses) on derivatives[2]	**(1,495)**	1,287	**(789)**	3,071
Realized revenue	**14,335**	22,797	**73,572**	89,199
Unrealized gains (losses) on derivatives	**(3,369)**	10,885	**(21,893)**	5,747
Total revenue	**10,966**	33,682	**51,679**	94,946
Realized revenue *($/boe)*	**19.50**	26.11	**22.43**	23.07
Total revenue *($/boe)*	**14.92**	38.57	**15.75**	24.55

(1) Includes revenues related to the market diversification contract and physical forward sales contracts which settled during the period.
(2) Includes realized gains (losses) on financial derivatives and certain financial prompt month price optimization contracts. Includes proceeds of $2.7 million ($0.17/Mcf) for the year ended December 31, 2019 received from the monetization of the Company's market diversification contract for the December 2019 to October 2020 period.

Realized revenue was $14.3 million in the fourth quarter of 2019, down 37% from the prior year period due to the 16% decrease in production combined with a 25% decrease in realized revenue per boe. For the fourth quarter of 2019, Perpetual recorded $1.5 million of realized losses on derivatives, comprised of $0.5 million from natural gas hedges and $1.0 million from crude oil and NGL hedges.

For the year ended December 31, 2019, realized revenue was $73.6 million, down 18% from the prior year as a result of the 15% decrease in production combined with a 3% decrease in realized revenue per boe. For the year ended December 31, 2019, Perpetual recorded $0.8 million of realized losses on derivatives, comprised of $3.4 million of gains on natural gas hedges which were more than offset by losses of $4.2 million from crude oil and NGL hedges.

Natural gas revenue, before derivatives, of $7.3 million in the fourth quarter of 2019 comprised 46% (Q4 2018 – 78%) of total P&NG revenue while natural gas production was 76% (Q4 2018 – 78%) of total production. Natural gas revenue decreased 57% from $16.7 million in the fourth quarter of 2018, reflecting significantly lower realized natural gas prices combined with an 18% decrease in natural gas production volumes driven by natural declines following limited capital investment targeting liquids-rich natural gas development in 2019. For the year ended December 31, 2019, natural gas revenue decreased by 28% compared to the prior year period, due primarily to the 20% decrease in natural gas production. Deliveries under Perpetual's market diversification contract contributed losses of $0.2 million ($0.05/Mcf) relative to the AECO Daily Index price in the quarter and contributed revenue of $9.9 million for the year ended December 31, 2019 ($0.64/Mcf). For the three months and year ended December 31, 2018, the market diversification contract contributed revenue of $6.8 million ($1.64/Mcf) and $19.5 million ($1.02/Mcf) respectively.

Oil revenue of $5.9 million represented 37% (Q4 2018 – 11%) of total P&NG revenue while oil production was 16% (Q4 2018 – 14%) of total production. Oil revenue was 142% higher than the same period in 2018 due to the 121% increase in realized oil prices, as crude oil production was unchanged from the prior year period. The higher WCS average reference price of $54.29/bbl was the result of a 60% narrowing of the WCS differential compared to the prior year period, more than offsetting the 3% decrease to US$ WTI benchmark prices. For the year ended December 31, 2019, oil revenue increased by 46% due to the 17% increase in crude oil production in combination with an 18% increase in WCS average prices.

NGL revenue for the fourth quarter of 2019 of $2.7 million comprised 17% (Q4 2018 – 11%) of total P&NG revenue while NGL production represented only 8% (Q4 2018 – 8%) of total Company production. NGL revenue increased by 15% over the prior year period, reflecting the 23% increase in realized NGL prices which more than offset the 15% decrease in NGL production over the same period. For the year ended December 31, 2019, NGL revenue decreased by 26% due to the 7% decrease in NGL production combined with a 23% decrease in realized NGL prices over the prior year. The decrease in NGL production reflected lower natural gas production at East Edson, partially offset by improved NGL yields following the installation of field compression equipment and a sweetening tower to restore higher liquids ratio natural gas wells back to production in the first half of 2019. East Edson production declines have been impacted by the Company's decision to defer liquids-rich gas drilling in response to lower Western Canadian natural gas prices.

Unrealized losses on derivatives of $3.4 million were recorded in the fourth quarter of 2019 (Q4 2018 – unrealized gain of $10.9 million). Unrealized gains and losses represent the change in mark-to-market value of derivative contracts as forward commodity prices and foreign exchange rates change. Unrealized gains and losses on derivatives are excluded from the Corporation's calculation of cash flow from operating activities as they are non-cash. Derivative gains and losses vary depending on the nature and extent of derivative contracts in place, which in turn, vary with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

Royalties

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Crown	**838**	496	**2,313**	2,497
Freehold and overriding(1)	**2,545**	1,787	**8,947**	8,097
Total	**3,383**	2,283	**11,260**	10,594
Crown (*% of P&NG revenue*)	**5.3**	2.3	**3.1**	2.9
Freehold and overriding (*% of P&NG revenue*)	**16.1**	8.3	**12.0**	9.4
Total (*% of P&NG revenue*)	**21.4**	10.6	**15.1**	12.3
$/boe	**4.60**	2.61	**3.43**	2.74

(1) Includes $1.9 million in gross overriding royalty payments at East Edson for the three months ended December 31, 2019 (Q4 2018 – $1.2 million) and $5.7 million for the year ended December 31, 2019 (2018 – $5.3 million).

Royalty expense for the fourth quarter of 2019 was $3.4 million, representing 21.4% of P&NG revenue (Q4 2018 – 10.6%) and up 48% from $2.3 million in the prior year period. Higher royalty rates reflect the increase in the Alberta Gas Reference Price and the AECO Daily Index price compared to the prior year period which are used to determine crown royalty and freehold and overriding royalty expense, respectively. At the East Edson property in West Central Alberta, the gross overriding royalty is equivalent to a maximum 5.6 MMcf/d of natural gas and associated NGL production. As West Central natural gas production has decreased by 16% compared to the fourth quarter of 2018, the fixed nature of the gross overriding royalty has resulted in an increased expense on a percentage of revenue and unit-of-production basis.

On an annual basis, royalty expense for 2019 was $11.3 million, representing 15.1% of P&NG revenue (2018 – 12.3%) and up 6% from $10.6 million in the prior year period. Average crown royalty rates increased to 3.1% in 2019 compared to 2.9% in 2018, due primarily to the impact of higher Alberta Gas Reference Prices compared to the prior year as well as the higher percentage of heavy oil in the production mix. Freehold and overriding royalties also increased as a percentage of P&NG revenue from 9.4% to 12.0%, as the AECO Daily Index increased 18% to $1.67/GJ (2018 - $1.42/GJ). In addition, as East Edson production decreased in 2019, the fixed volume nature of the gross overriding royalty resulted in an increased expense as a percentage of revenue and on a unit-of-production basis, which also contributed to the increased overriding royalty rate in 2019.

Production and operating expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Production and operating expenses	**3,839**	4,851	**18,332**	19,229
$/boe	**5.22**	5.56	**5.59**	4.97

Production and operating expenses decreased 21% to $3.8 million in the fourth quarter of 2019 compared to $4.9 million recorded during the same period in 2018 due to reduced costs in Eastern Alberta associated with maintenance activities and the absence of remediation costs from the 2018 Mannville produced water spill. Production and operating expenses per boe decreased by 6% from the prior year period, as lower production and operating costs were partially offset by the 16% decrease in production.

On an annual basis, production and operating expenses decreased 5% to $18.3 million in 2019 compared to $19.2 million in 2018. This decrease reflected remediation and additional water hauling costs of $1.0 million incurred in the third and fourth quarters of 2018 from the Mannville produced water spill. Production and operating expenses averaged $2.74/boe at West Central compared to $16.84/boe at Eastern Alberta, due to the higher cost nature of Eastern Alberta heavy oil production, including waterflood operations at Mannville. In addition, extremely high property taxes related to mature assets contributed $2.32/boe to operating costs in Eastern Alberta in 2019.

Transportation costs

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Transportation costs	**1,551**	1,489	**6,258**	6,068
$/boe	**2.11**	1.71	**1.91**	1.57

Transportation costs include clean oil trucking and NGL transportation as well as costs to transport natural gas from the plant gate to commercial sales points. For the fourth quarter of 2019, transportation costs were $1.6 million, comparable with the fourth quarter of 2018. On a unit-of-production basis, company-wide transportation costs increased by 23% from $1.71/boe in the fourth quarter of 2018 to $2.11/boe in the same period of 2019, due to the impact of unutilized demand charges from firm natural gas pipeline capacity at East Edson combined with the 16% decrease in production. Transportation costs averaged $1.64/boe at West Central compared to $3.80/boe for production from Eastern Alberta.

For the year ended December 31, 2019, transportation costs were $6.3 million, an increase of 3% over 2018. The increase was due to higher per unit trucking costs in Eastern Alberta, where crude oil production increased by 19% year-over-year.

Gas over bitumen

($ thousands, except as noted)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
Gas over bitumen royalty credit	**202**	302	**852**	1,046
Payments of gas over bitumen royalty financing[1]	**(225)**	(257)	**(1,013)**	(1,135)
Gas over bitumen, net of payments	**(23)**	45	**(161)**	(89)
$/boe	**(0.03)**	0.05	**(0.05)**	(0.02)

(1) At December 31, 2019, the fair value of the remaining gas over bitumen royalty financing obligation is estimated to be $0.9 million (2018 – $1.1 million).

Perpetual records revenue in relation to gas over bitumen royalty credits received under the Natural Gas Royalty Regulation as a result of its working interests in a number of natural gas wells which have been shut-in pursuant to shut-in orders issued by the Government of Alberta. For the year ended December 31, 2019, Perpetual recorded $0.9 million in gas over bitumen revenue, a decrease of 19% from 2018. The decrease was attributable to the annual 10% decline in deemed production, combined with the expiry of certain gas over bitumen royalty credits for wells that were shut-in during the fourth quarter of 2009.

Gas over bitumen royalty credits earned throughout 2019 were offset by payments of $1.0 million (2018 – $1.1 million) in relation to the 2014 monetization of Perpetual's future gas over bitumen royalty credits. The payment commitment expires concurrent with the cessation of the gas over bitumen royalty credit, with final payments expected to occur in June 2021.

Under IFRS, the monetization of future gas over bitumen royalty credits is recorded as a financial obligation ("Gas over bitumen royalty financing"); however, entitlement to future revenues from gas over bitumen royalty credits are not recorded as an asset, but as revenue with the passage of time as it is earned. As such, gas over bitumen royalty credits will continue to be recognized separately as revenue in accordance with Perpetual's accounting policies, with the monthly payments recognized as a reduction to the gas over bitumen royalty financing obligation. For purposes of this MD&A, the monthly payments are included as a reduction to gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty credits. During the fourth quarter of 2019, the gas over bitumen royalty financing obligation decreased by $0.1 million, comprised of payments of $0.2 million which were partially offset by an unrealized loss of $0.1 million. The loss has been included in non-cash finance expense and represents an increase in the fair value of the gas over bitumen royalty financing obligation during the fourth quarter of 2019, reflecting higher forecast natural gas reference prices based on the AECO forward market.

During 2019, the gas over bitumen royalty financing obligation was reduced by $0.3 million, comprised of payments of $1.0 million (2018 – $1.1 million) which were partially offset by an unrealized loss of $0.7 million (2018 – unrealized gain of $0.5 million). The loss has been included in non-cash finance expense and represents an increase in the fair value of the gas over bitumen royalty financing obligation compared to 2018, as a result of higher forecast natural gas reference prices based on the AECO forward market.

Exploration and evaluation ("E&E") expenses

($ thousands)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
Lease rentals[1]	**52**	132	**190**	649
Geological and geophysical costs	**–**	–	**8**	78
Lease expiries (non-cash)	**759**	1,485	**1,599**	1,485
Total E&E expense	**811**	1,617	**1,797**	2,212

(1) Commencing in the second quarter of 2019, developed mineral lease rentals have been classified as production and operating expenses.

Exploration and evaluation expenses include lease rentals on undeveloped acreage, geological and geophysical costs, and the write-down of carrying costs related to lease expiries. During the fourth quarter of 2019, the Company recorded $0.8 million of non-cash write-downs associated with certain undeveloped lands that were either allowed to expire, or are no longer part of Perpetual's future development plans. For the year ended December 31, 2019, Perpetual recorded $1.6 million of non-cash write-downs associated with undeveloped lands that were allowed to expire (2018 – $1.5 million).

General and administrative ("G&A") expenses

($ thousands, except as noted)	Three months ended December 31, 2019	2018[1]	Years ended December 31, 2019	2018[1]
Cash G&A expense	**2,604**	4,246	**12,808**	15,459
Overhead recoveries	**(198)**	(453)	**(1,148)**	(1,829)
Total G&A expense	**2,406**	3,793	**11,660**	13,630
$/boe	**3.27**	4.34	**3.55**	3.52

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

During the fourth quarter of 2019, cash G&A expense was $2.6 million, a 39% decrease from the prior year period of $4.2 million due primarily to the reduction of approximately 25% of Perpetual's corporate employee head count, combined with a reduction in compensation for remaining employees that was implemented at the end of the third quarter. Fourth quarter 2019 overhead recoveries decreased by 56% relative to the 2018 period due to limited capital spending. On a unit-of-production basis, total G&A expense was down 25% to $3.27/boe for the three months ended December 31, 2019, as lower costs were partially offset by the 16% decline in production compared to the prior year period.

For the year ended December 31, 2019, total G&A expense decreased by 14% over the prior year period, due primarily to cost reductions implemented at the end of the third quarter, partially offset by lower overhead recoveries triggered by the reduction in capital expenditures from $26.9 million in 2018 to $12.9 million in 2019. On a unit-of-production basis, total G&A expense of $3.55/boe for the year ended December 31, 2019 was comparable to the prior year period of $3.52/boe, as the decrease in production was almost completely offset by lower overall costs.

Restructuring costs

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Restructuring costs	**–**	–	**1,546**	–

In response to the decrease in forward commodity prices, the Company implemented a restructuring plan at the end of the third quarter which resulted in the reduction of approximately 25% of Perpetual's corporate employee head count. Restructuring costs of $1.5 million were expensed in the third quarter of 2019, of which $0.6 million was paid during the fourth quarter and $0.9 million is anticipated to be fully paid by the end of 2020. Annual cost savings of $3.5 million are anticipated, commencing in the fourth quarter of 2019.

Share-based payments

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Share-based payments (non-cash)	**123**	566	**406**	2,573
Share-based payments (cash)	**365**	–	**1,889**	–
Total share-based payments	**488**	566	**2,295**	2,573

Share-based payments expense for the three months ended December 31, 2019 was $0.5 million, down 14% from the same period in 2018 due to a reduction in the performance multiplier estimate applicable to performance share rights, combined with a reduction in the number of outstanding share-based payment awards. No new awards were granted to employees in the fourth quarter of 2019, while 0.1 million deferred shares were granted to Directors of the Company. For the year ended December 31, 2019, share-based payments expense was $2.3 million, 11% lower than the prior year period for the same reasons noted above.

Depletion and depreciation

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018(1)	**2019**	2018(1)
Depletion and depreciation	**6,960**	7,777	**31,188**	34,946
$/boe	**9.47**	8.91	**9.51**	9.04

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

Perpetual recorded $31.2 million of depletion and depreciation expense for the year ended December 31, 2019, down 11% from $34.9 million in 2018 due to the 15% decrease in production volumes compared to the prior year. On a per boe basis, depletion and depreciation expense of $9.51/boe was 5% higher than the prior year, due primarily to the higher depletion rates associated with the Company's Eastern Alberta assets, which make up a larger percentage of Perpetual's total production on which depletion expense is recorded. The Company's 2019 capital program added proved plus probable reserves that replaced 74% of 2019 production (2018 – 134% of production) at F&D costs of $10.54/boe, including FDC (2018 **–** $5.09/boe).

Impairment

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. For the quarter ended December 31, 2019, the Company conducted an assessment of impairment indicators for the Company's CGUs. In performing the review, management determined that the considerable economic instability and uncertainty in the oil and natural gas markets which negatively impacts operating cash flows, coupled with the Company's available liquidity at December 31, 2019, justified calculation of the recoverable amount of the liquids-rich natural gas assets which comprise the West Central CGU. The recoverable amount of the West Central CGU was determined using value-in-use ("VIU") based on the net present value of cash flows from oil, natural gas, and NGL reserves using estimates of total proved plus probable reserves evaluated or reviewed by the Company's independent reserves evaluators, along with commodity price estimates based on an average of three independent reserve evaluators, and an estimate of market discount rates between 10% and 22% to consider risks specific to the asset.

At December 31, 2019, the Company determined that the carrying amount of the West Central CGU exceeded the recoverable amount of $130.8 million and accordingly, an impairment charge of $23.8 million was included in net loss.

During the fourth quarter of 2019, the Company decommissioned its Panny natural gas properties due to an excessive property tax burden and determined that the associated $0.7 million carrying value was no longer recoverable. Accordingly, a $0.7 million impairment charge was included in net loss.

At June 30, 2019, the Company determined that the carrying amount of the West Central CGU exceeded the recoverable amount of $165.0 million and accordingly, an impairment charge of $22.6 million was included in net loss.

Finance expenses

($ thousands)	Three months ended December 31, **2019**	2018	Years ended December 31, **2019**	2018
Cash finance expense				
Interest on revolving bank debt	**788**	633	**2,880**	2,226
Interest on TOU share margin demand loan	**72**	130	**407**	570
Interest on term loan	**936**	936	**3,645**	3,665
Interest on senior notes	**735**	710	**2,921**	2,864
Interest on lease liabilities[(1)]	**44**	–	**189**	–
Dividend income from TOU share investment	**(199)**	(167)	**(762)**	(618)
Total cash finance expense	**2,376**	2,242	**9,280**	8,707
Non-cash finance expense				
Amortization of debt issue costs	**326**	262	**1,187**	1,026
Accretion on decommissioning obligations	**162**	216	**752**	841
Change in fair value of gas over bitumen royalty financing	**117**	(414)	**732**	(452)
Total non-cash finance expense	**605**	64	**2,671**	1,415
Finance expenses recognized in net loss	**2,981**	2,306	**11,951**	10,122

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

Total cash finance expense was $2.4 million in the fourth quarter of 2019, 6% higher than the prior year period. The change was due to increased interest expense on the revolving Credit Facility associated with higher floating interest rates, increased borrowing amounts associated with the partial repayment of the TOU share margin demand loan during the second half of 2019, and a higher principal amount of senior notes outstanding as a result of the senior note refinancing completed in June 2019. Increased interest on revolving bank debt was partially offset by lower interest on the TOU share margin demand loan and higher dividend income from the Company's TOU share investment. On an annual basis, total cash finance expense was $9.3 million, up $0.6 million from 2018 for the same reasons noted above. Credit Facility borrowing costs have increased by 1% as a result of the borrowing base redetermination that was completed in late December.

Total non-cash finance expense for the three months ended December 31, 2019 was $0.6 million, up $0.5 million from 2018. The increase was due primarily to the change in fair value of the gas over bitumen royalty financing, which resulted in an unrealized loss of $0.1 million during the fourth quarter of 2019 compared to an unrealized gain of $0.4 million in 2018. The loss represents an increase in the fair value of the gas over bitumen royalty financing obligation compared to 2018, as a result of higher forecast natural gas reference prices based on the AECO forward market. For the year ended December 31, 2019, non-cash finance expense was $2.7 million, 89% higher than the prior year period and again caused by the change in fair value of the gas over bitumen royalty financing.

Change in fair value of TOU share investment

In December 2019, the Company sold 656,773 TOU shares at a weighted average price of $14.78 per share, for net cash proceeds of $9.7 million. Proceeds from the sale of TOU shares were used to pay down the balance of the TOU share margin demand loan by $9.1 million. The remaining proceeds were used to repay Credit Facility borrowings.

At December 31, 2019, the Company held 1.0 million (December 31, 2018 – 1.66 million shares) TOU shares with a fair market value of $15.2 million (December 31, 2018 – $28.1 million). For the year ended December 31, 2019, Perpetual recorded an unrealized loss of $3.2 million related to the change in fair value of the TOU share investment, which represents the change in value of TOU shares held from December 31, 2018 ($16.98 per share) to December 31, 2019 ($15.22 per share).

In January 2020, the Company sold its remaining 1,000,000 TOU shares at a weighted average price of $14.32 per share, for net cash proceeds of $14.3 million. Net proceeds were used to repay the remaining $0.1 million TOU share margin demand loan, with the balance used to repay a portion of the Credit Facility.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Perpetual's strategy targets the maintenance of a strong capital base to retain investor, creditor and market confidence to support the execution of its business plans. The Company manages its capital structure and adjusts its capital spending in light of changes in economic conditions such as depressed commodity prices, available liquidity, and the risk characteristics of its underlying oil and natural gas assets. The Company considers its capital structure to include share capital, senior notes, the term loan, revolving bank debt, and net working capital. To manage its capital structure and available liquidity, the Company may from time to time issue equity or debt securities, sell assets, and adjust its capital spending to manage current and projected debt levels. The Company will continue to regularly assess changes to its capital structure and repayment alternatives, with considerations for both short-term liquidity and long-term financial sustainability.

Capital Management

(*$ thousands, except as noted*)	**December 31, 2019**	December 31, 2018
Revolving bank debt	**47,552**	42,561
Term loan, principal amount	**45,000**	45,000
TOU share margin demand loan, principal amount	**100**	14,144
Senior notes, principal amount	**33,580**	32,490
TOU share investment(1)	**(15,220)**	(28,132)
Net working capital deficiency(2)	**7,068**	6,543
Net debt(2)	**118,080**	112,606
Shares outstanding at end of period (*thousands*)(3)	**60,513**	60,240
Market price at end of period (*$/share*)(3)	**0.07**	0.20
Market value of shares	**4,236**	12,048
Enterprise value(2)	**122,316**	124,654
Net debt as a percentage of enterprise value	**97**	90
Trailing twelve months adjusted funds flow(2)	**14,534**	30,155
Net debt to trailing twelve months adjusted funds flow	**8.1**	3.7

(1) The TOU share investment is based on the December 31, 2019 closing price per the Toronto Stock Exchange ($15.22 per share) and 1.0 million TOU shares held (December 31, 2018 – 1.66 million TOU shares held with a closing price of $16.98 per share).
(2) See "Non-GAAP measures" in this MD&A.
(3) Shares outstanding are presented net of shares held in trust.

At December 31, 2019, Perpetual had total net debt of $118.1 million, up $5.5 million (5%) from December 31, 2018. The increase was due primarily to a $3.2 million decrease in the fair value of the TOU share investment during 2019, combined with an incremental $1.1 million of 2022 Senior Notes that were issued in connection with the early redemption of the 2019 Senior Notes in the second quarter. Revolving bank debt increased by $5.0 million during 2019 to $47.6 million at December 31, 2019 due to a $5.0 million repayment of the TOU share margin demand loan during the year.

As at December 31, 2019, 67% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow increased to 8.1 times at December 31, 2019 (December 31, 2018 – 3.7 times).

TOU share margin demand loan

At December 31, 2019, Perpetual had a $0.1 million non-revolving TOU share margin demand loan secured by 1.0 million TOU shares. Interest rates are based on 90-day Banker's Acceptance rates plus 1.25%. Perpetual may repay a portion or the entirety of the loan at any time. Any repayment is a permanent reduction to the loan.

In December 2019, Perpetual sold 656,773 TOU shares at a weighted average price of $14.78 per share and used the proceeds of $9.7 million to partially repay the TOU share margin demand loan. Total loan repayments of $14.0 million were made during 2019. In January 2020, the Company sold its remaining 1,000,000 TOU shares for net cash proceeds of $14.3 million. Net proceeds were used to fully repay the TOU share margin demand loan and to repay a portion of the Credit Facility.

Revolving bank debt

As at December 31, 2019, the Company's Credit Facility had a Borrowing Limit of $55.0 million (December 31, 2018 – $55.0 million) under which $47.6 million was drawn (December 31, 2018 – $42.6 million) and $2.3 million of letters of credit had been issued (December 31, 2018 – $3.7 million). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 3.0% and 5.5%.

On December 24, 2019, Perpetual's syndicate of Credit Facility lenders completed their semi-annual borrowing base redetermination, reducing the Borrowing Limit from $55 million to $45 million on January 22, 2020, with the maturity date remaining at November 30, 2020. Previously, on March 27, 2019, the Company's lenders confirmed the $55 million Borrowing Limit and the maturity was extended to November 30, 2020. As a result, revolving bank debt has been presented as a current liability on the consolidated statements of financial position as at December 31, 2019.

The next Borrowing Limit redetermination is scheduled on or prior to March 31, 2020. The Credit Facility will revolve until March 31, 2020 and may be extended for a period of up to 364-days subject to approval by the Company's lenders. If not extended, the Credit Facility will cease to revolve, and all outstanding advances will be repayable on November 30, 2020.

The Credit Facility is secured by general, first lien security agreements covering all present and future property of the Company and its subsidiaries, with the exception of certain lands pledged to the gas over bitumen royalty financing counterparty. The Credit Facility also contains provisions which restrict the Company's ability to repay second lien and unsecured debt and to pay dividends on or repurchase its common shares.

The effective interest rate on the Credit Facility at December 31, 2019 was 7.5% (December 31, 2018 – 6.2%). If interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net loss would be $0.5 million.

At December 31, 2019, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term loan

	Maturity date	Interest rate	December 31, 2019 Principal	December 31, 2019 Carrying Amount	December 31, 2018 Principal	December 31, 2018 Carrying amount
Term loan	March 14, 2021	8.1%	**$ 45,000**	**$ 44,274**	$ 45,000	$ 43,729

The term loan bears a fixed interest rate of 8.1% with semi-annual interest payments due June 30 and December 31 of each year. Amounts borrowed under the term loan that are repaid are not available for re-borrowing. The Company may repay the term loan at any time without penalty.

The term loan has a cross-default provision with the Credit Facility and contains substantially similar covenants as the Credit Facility. The term loan is secured by a general security agreement over all present and future property of the Company and its subsidiaries on a second priority basis, subordinate only to liens securing loans under the Credit Facility, and certain lands pledged to the gas over bitumen royalty financing counterparty.

At December 31, 2019, the term loan is presented net of $0.7 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 9.5%.

At December 31, 2019, the term loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

	Maturity date	Interest rate	December 31, 2019 Principal	December 31, 2019 Carrying Amount	December 31, 2018 Principal	December 31, 2018 Carrying amount
2019 Senior Notes	July 23, 2019	8.75%	**$ –**	**$ –**	$ 14,572	$ 14,536
2022 Senior Notes	January 23, 2022	8.75%	**33,580**	**32,255**	17,918	17,344
			$ 33,580	**$ 32,255**	$ 32,490	$ 31,880

On May 7, 2019, Perpetual announced the early redemption of all of the $14.6 million aggregate principal amount of 8.75% senior notes maturing July 23, 2019 (the "2019 Senior Notes") effective June 11, 2019 (the "Redemption Date"). Pursuant to the early redemption, holders of the 2019 Senior Notes would receive CDN $1,000 for each $1,000 principal amount of 2019 Senior Notes (the "Cash Consideration"); or, at the election of the holder, $1,075 principal amount of 8.75% senior notes due January 23, 2022 (the "2022 Senior Notes") for each $1,000 principal amount of 2019 Senior Notes (the "2022 Senior Notes Consideration") plus cash in the amount of $33.32 per $1,000 principal amount of 2019 Senior Notes, representing all accrued and unpaid interest at the Redemption Date.

On June 11, 2019, the Company completed the early redemption of the $14.6 million 2019 Senior Notes. Pursuant to the early redemption, the Company issued $15.7 million of 2022 Senior Notes to fully redeem the 2019 Senior Notes, of which $15.6 million 2022 Senior Notes were issued to entities controlled by or associated with the Company's CEO. There was no gain or loss on the exchange. After giving effect to this senior note refinancing, there are $33.6 million 2022 Senior Notes outstanding comprised of $17.9 million 2022 Senior Notes previously outstanding, and the $15.7 million 2022 Senior Notes issued as consideration to redeem the 2019 Senior Notes. Entities controlled by the Company's CEO hold $13.4 million of the 2022 Senior Notes now outstanding. An entity that is associated with the Company's CEO holds an additional $9.1 million of the 2022 Senior Notes now outstanding.

The 2022 Senior Notes bear a fixed interest rate of 8.75% with semi-annual interest payments due January 23 and July 23 of each year. The senior notes are direct senior unsecured obligations of the Company, ranking pari passu with all other present and future unsecured and unsubordinated indebtedness of the Company. Prior to January 23, 2021, the Company may redeem up to 100% of the senior notes at 103.3% of the principal amount. Subsequent to January 23, 2021, the Company may redeem up to 100% of the senior notes at the principal amount.

At December 31, 2019, the 2022 Senior Notes are recorded at the present value of future cash flows, net of issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 10.9%.

The senior notes have a cross-default provision with the Company's Credit Facility. In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt, and stock repurchases.

At December 31, 2019, other than the restricted payment covenants noted above, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Equity

At December 31, 2019 there were 60.5 million common shares outstanding, net of 0.8 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended December 31, 2019 were 60.4 million (Q4 2018 – 60.4 million) and 60.3 million for the year ended December 31, 2019 (2018 – 60.0 million).

At March 18, 2020 there were 60.7 million common shares outstanding which is net of 0.6 million shares held in trust for employee compensation programs. In addition, the following potentially issuable common shares were outstanding as at the date of this MD&A:

(millions)	**March 18, 2020**
Share options	**4.6**
Performance share rights(1)	**2.7**
Compensation awards(1)	**4.7**
Total	**12.0**

(1) 2.7 million performance share rights have an exercise price below the December 31, 2019 closing price of the Company's common shares of $0.07 per share.

Contractual obligations

At December 31, 2019, the Company's minimum contractual obligations over the next five years and thereafter, excluding estimated interest payments are as follows:

	2020	**2021**	**2022**	**2023**	**2024 and thereafter**	**Total**
Contractual obligations						
Accounts payable and accrued liabilities	13,278	–	–	–	–	13,278
Fair value of derivative liabilities	10,542	2,732	–	–	–	13,274
TOU share margin demand loan, principal amount	100	–	–	–	–	100
Revolving bank debt	47,552	–	–	–	–	47,552
Term loan, principal amount	–	45,000	–	–	–	45,000
Senior notes, principal amount	–	–	33,580	–	–	33,580
Gas over bitumen royalty financing	582	289	–	–	–	871
Lease liabilities	633	567	492	460	533	2,685
Pipeline transportation commitments	3,030	1,870	945	945	945	7,735
Total	**75,717**	**50,458**	**35,017**	**1,405**	**1,478**	**164,075**

The Company anticipates that it will require additional financing or a potential refinancing plan to address the anticipated liquidity shortfall and the upcoming debt maturities. Perpetual is considering options including arranging for extensions of the debt maturity dates, alternative refinancing or additional financing arrangements, or the sale or monetization of other assets. Refer to the future operations section of this MD&A.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q4 2019**	Q3 2019	Q2 2019	Q1 2019
Financial				
Oil and natural gas revenue	**15,830**	17,097	19,235	22,199
Net loss	**(32,498)**	(20,349)	(36,276)	(4,892)
Per share – basic and diluted	**(0.54)**	(0.34)	(0.60)	(0.08)
Cash flow from (used in) operating activities	**(1,290)**	5,509	4,295	9,292
Adjusted funds flow[1]	**340**	4,183	3,649	6,362
Per share – basic and diluted	**0.01**	0.07	0.06	0.11
Capital expenditures	**1,995**	4,506	5,200	1,238
Net payments (proceeds) on acquisitions and dispositions	**–**	–	–	–
Net capital expenditures	**1,995**	4,506	5,200	1,238
Common shares *(thousands)*				
Weighted average – basic and diluted	**60,444**	60,317	60,154	60,111
Operating				
Daily average production				
Natural gas *(MMcf/d)*	**36.6**	38.2	44.5	50.0
Oil *(bbl/d)*	**1,275**	1,292	1,207	1,121
NGL *(bbl/d)*	**606**	731	754	785
Total *(boe/d)*	**7,991**	8,383	9,370	10,240
Average prices				
Realized natural gas price *($/Mcf)*[2]	**2.00**	3.13	2.25	3.54
Realized oil price *($/bbl)*[2]	**43.85**	44.31	50.01	41.12
Realized NGL price *($/bbl)*[2]	**43.93**	37.34	51.34	32.16

($ thousands, except where noted)	Q4 2018[3]	Q3 2018[3]	Q2 2018[3]	Q1 2018[3]
Financial				
Oil and natural gas revenue	21,510	20,504	20,774	23,340
Net loss	(331)	(12,259)	(1,325)	(6,465)
Per share – basic and diluted	(0.01)	(0.20)	(0.02)	(0.11)
Cash flow from operating activities	5,163	6,729	8,435	11,198
Adjusted funds flow[1]	8,052	5,155	7,847	9,101
Per share – basic	0.13	0.09	0.13	0.15
Net capital expenditures				
Capital expenditures	5,617	4,343	2,031	14,897
Net payments (proceeds) on acquisitions and dispositions	(1,285)	4,341	(7,012)	926
Net capital expenditures	4,332	8,684	(4,981)	15,823
Common shares (*thousands*)				
Weighted average – basic and diluted	60,448	60,468	59,876	59,345
Operating				
Daily average production				
Natural gas (*MMcf/d*)	44.9	46.9	53.1	65.9
Oil (*bbl/d*)	1,301	1,022	971	900
NGL (*bbl/d*)	715	730	806	848
Total (*boe/d*)	9,491	9,569	10,620	12,742
Average prices				
Realized natural gas price (*$/Mcf*)[2]	4.38	2.83	2.62	2.65
Realized oil price (*$/bbl*)[2]	19.83	48.57	53.26	48.31
Realized NGL price (*$/bbl*)[2]	35.73	56.02	60.77	57.61

(1) See "Non-GAAP measures" in this MD&A.
(2) Realized natural gas and oil prices include physical forward sales contracts for which delivery was made during the reporting period, along with realized gains and losses on financial derivatives and foreign exchange contracts.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

The Company's oil and natural gas revenue, net loss, cash flow from (used in) operating activities and adjusted funds flow are influenced by commodity prices and production levels. Natural gas production levels decreased during 2018 and 2019 due to natural declines and reduced capital expenditures in response to depressed AECO natural gas prices, and due to the shut-in of approximately 700 boe/d of production during the second, third and fourth quarters of 2018 at East Edson associated with the Sequoia bankruptcy. This production was restarted in mid-December 2018, causing natural gas production to increase temporarily in the first quarter of 2019. Oil-focused capital expenditures increased in the second and third quarters of 2019, as improved oil prices and differentials supported investment.

The net loss for the fourth quarter of 2019 was $32.5 million ($0.54/share). The Company recognized impairment charges of $22.6 million and $24.5 million in the second and fourth quarters of 2019, respectively, along with $1.5 million of restructuring costs during the third quarter of 2019.

Commodity price risk management and sales obligations

Perpetual's commodity price risk management strategy is focused on managing downside risk and increasing certainty in adjusted funds flow by mitigating the effect of commodity price volatility. Physical forward sales and financial derivatives are used to manage the balance sheet, to lock in economics on capital programs and to take advantage of perceived anomalies in commodity markets. Perpetual also utilizes foreign exchange derivatives and physical or financial derivatives related to the differential between natural gas prices at the AECO and NYMEX trading hubs and oil basis differentials between WTI and WCS in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Corporation's realized revenue. Diversification of markets is a further risk management strategy employed by the Company.

The following tables provide a summary of commodity price risk management contracts outstanding at March 18, 2020:

Natural Gas

The Company has open physical and financial basis differential contracts between AECO and NYMEX. Settlements on physical sales contracts are recognized in oil and natural gas revenue.

Term	Volumes sold (bought) *(MMBtu/d)*	AECO-NYMEX differential *(US$/MMBtu)*[1]	Market prices *(US$/MMBtu)*[2]	Type of contract
January 2020 – December 2020	12,500	(1.41)	(0.58)	Physical
January 2020 – December 2020	15,000	(1.41)	(0.58)	Financial
January 2021 – December 2021	15,000	(1.31)	(0.84)	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for January, February and March 2020 are based on settled AECO-NYMEX differential prices. Market prices for subsequent months are based on forward AECO-NYMEX differential prices as of market close on March 18, 2020.

Crude Oil

The Company had entered into the following financial fixed price oil sales arrangements which settle in US$ as follows:

Term	Volumes *(bbl/d)*	WTI average price *(US$/bbl)*	Market prices *(US$/bbl)*[1]	Type of contract
January 2020 – October 2020	100	57.90	30.05	Financial
January 2020 – December 2020	750	53.07	29.68	Financial

(1) Market prices for January and February 2020 are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on March 18, 2020.

The following table provides a summary of basis differential contracts between WTI and WCS:

Term	Volumes *(bbl/d)*	WTI-WCS differential *(US$/bbl)*[1]	Market prices *(US$/bbl)*[2]	Type of contract
January 2020 – December 2020	750	(18.75)	(15.99)	Financial
March 2020 – October 2020	100	(17.65)	(14.63)	Financial

(1) Average price calculated using weighted average price for net open contracts; contracts settle at WTI index less a fixed basis amount.
(2) Market prices for January, February and March 2020 are based on settled WTI-WCS differential prices. Market prices for subsequent months are based on forward WTI-WCS differential prices as of market close on March 18, 2020.

The following table provides a summary of WCS fixed price contracts which settle in Cdn$:

Term	Volumes *(bbl/d)*	WCS average price *($/bbl)*	Market prices *($/bbl)*[1]	Type of contract
January 2020 – December 2020	250	50.00	21.13	Financial

(1) Market prices for January and February 2020 are based on settled WCS oil prices. Market prices for subsequent months are based on forward WCS oil prices as of market close on March 18, 2020.

NGL

The following table provides a summary of financial NGL basis differential arrangements between WTI and Edmonton condensate pricing:

Term	Volumes *(bbl/d)*	WTI Edmonton condensate differential *(US$/bbl)*[1]	Market prices *(US$/bbl)*[2]	Type of contract
January 2020 – June 2020	350	(6.15)	(0.79)	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for January, February and March 2020 are based on settled WTI Edmonton condensate differential prices. Market prices for subsequent months are based on forward WTI Edmonton condensate differential prices as of market close on March 18, 2020.

Foreign Exchange

The Company had entered into the following US$ forward sales arrangements to manage the Company's exposure to US$ denominated crude oil sales:

Term	**Notional** ***(US$ thousands/month)***	**Strike rate** ***(US$/Cdn$)***[(1)]	**Market prices** ***(US$/Cdn$)***[(2)]
January 2020 – March 2020	2,000	1.29	1.35

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for January and February 2020 are based on settled US$/Cdn$ exchange rates. Market prices for subsequent months are based on forward US$/Cdn$ exchange rates as of market close on March 18, 2020.

Natural Gas Sales Obligations

Natural gas volumes sold pursuant to the Company's market diversification contract are sold at fixed volume obligations of 40,000 MMBtu/d and priced at daily index prices at each of the market price points, less transportation costs from AECO to each market price point as detailed below.

In the third quarter of 2019, Perpetual extended the term of its market diversification contract by two years. From November 1, 2022 to October 31, 2024, Perpetual will deliver 40,000 MMBtu/d at AECO and receive Malin, Dawn, and Emerson daily index prices less US$0.0775/MMBtu and transportation costs from AECO to the market price point.

In late September 2019, the Company modified its market diversification contract to forgo its right to receive pricing at five North American natural gas hub pricing points for the period commencing December 1, 2019 and ending on October 31, 2020 in consideration for receipt of payment of $2.7 million. The amount has been recognized in revenue as a realized gain on derivatives.

Market/Pricing Point	**November 1, 2020 to October 31, 2022 Daily sales volume** ***(MMBtu/d)***	**November 1, 2022 to October 31, 2024 Daily sales volume** ***(MMBtu/d)***
Chicago	12,200	–
Malin	10,800	15,000
Dawn	8,000	15,000
Michcon	5,200	–
Empress	3,800	–
Emerson	–	10,000
Total natural gas sales volume obligation	**40,000**	**40,000**

SELECTED ANNUAL INFORMATION

($ thousands, except where noted)	**2019**	2018[4]	2017[4]
Financial			
Oil and natural gas revenue	**74,361**	86,128	81,722
Net income (loss)	**(94,015)**	(20,380)	(35,971)
Per share – basic and diluted[1]	**(1.56)**	(0.34)	(0.62)
Cash flow from (used in) operating activities	**17,806**	31,525	19,170
Adjusted funds flow	**14,534**	30,155	31,115
Per share[1][2]	**0.24**	0.50	0.54
Total assets	**241,148**	335,089	365,570
Total long-term liabilities	**118,061**	101,870	144,186
Revolving bank debt	**47,552**	42,561	31,581
Senior notes, principal amount	**33,580**	32,490	32,490
Term loan, principal amount	**45,000**	45,000	45,000
TOU share margin demand loan, principal amount	**100**	14,144	18,490
TOU share investment	**(15,220)**	(28,132)	(37,985)
Net working capital deficiency	**7,068**	6,543	16,404
Total net debt	**118,080**	112,606	105,980
Net capital expenditures			
Capital expenditures	**12,939**	26,888	73,035
Net payments (proceeds) on acquisitions and dispositions	**–**	(3,030)	2,422
Net capital expenditures	**12,939**	23,858	75,457
Common shares (*thousands*)			
End of period[3]	**60,513**	60,240	59,263
Weighted average – basic	**60,258**	60,039	58,017
Weighted average – diluted	**60,258**	60,039	58,017
Operating			
Daily average production			
Natural gas (*MMcf/d*)	**42.3**	52.6	49.6
Oil (*bbl/d*)	**1,224**	1,050	948
NGL (*bbl/d*)	**719**	774	655
Total average production (*boe/d*)	**8,988**	10,594	9,876
Average prices			
Realized natural gas price *($/Mcf)*	**2.77**	3.05	3.51
Realized oil price *($/bbl)*	**44.87**	40.62	41.62
NGL price (*$/bbl*)	**41.01**	52.96	46.60
Wells drilled			
Natural gas – gross (net)	**– (–)**	1 (1.0)	15 (14.4)
Crude oil – gross (net)	**5 (5.0)**	6 (6.0)	4 (3.3)
Total – gross (net)	**5 (5.0)**	7 (7.0)	19 (17.7)

(1) Based on weighted average common shares outstanding for the year.
(2) See "Non-GAAP measures" in this MD&A.
(3) Reduced by shares held in trust (2019 – 801; 2018 – 661; and 2017 – 447). See "Note 17 to the Audited Consolidated Financial Statements".
(4) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

FUTURE ACCOUNTING PRONOUNCEMENTS

Recently adopted

IFRS 16 "Leases"
On January 1, 2019, Perpetual adopted IFRS 16 using the modified retrospective approach. This approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to opening retained earnings and applies the standard prospectively. Therefore, the comparative information in the consolidated financial statements has not been restated.

IFRS 16 requires entities to recognize lease liabilities in relation to leases which had previously been classified as operating leases under the principles of IAS 17, "Leases" ("IAS 17"). Under the principles of the new standard, these leases have been measured at the present value of the remaining lease payments, discounted using Perpetual's estimated incremental borrowing rates at January 1, 2019, adjusted for the term and nature of leased assets. Incremental borrowing rates as at January 1, 2019 ranged from 4.3% to 6.6%. The associated right-of-use ("ROU") assets were measured at an amount equal to the lease liability on January 1, 2019, with no impact on retained earnings.

On adoption, the Corporation elected to use the following practical expedients permitted under the new standard:

- ROU assets and lease liabilities for leases with a remaining term of less than twelve months as at January 1, 2019 were not recognized;
- ROU assets and lease liabilities for leases of low dollar value were not recognized;
- Applied a single discount rate to a portfolio of leases with similar characteristics;
- Excluded initial direct costs from measuring ROU assets at the date of initial application; and
- Adjusted the ROU assets by the amount of an IAS 37 lease inducement provision immediately before the date of initial application, as an alternative to an impairment review.

The impact of the adoption of IFRS 16 as at January 1, 2019 is as follows:

- Recorded lease liabilities of $3.1 million; and
- Recorded ROU assets of $1.8 million, equal to the lease liabilities of $3.1 million less $1.3 million previously recognized as a lease inducement under IAS 37. ROU assets are comprised of $1.5 million for the head office lease, $0.2 million for vehicle leases, and $0.1 million for other leases.

The adoption of the new standard had the following impact on the Company's financial results for the year ended December 31, 2019, compared to what would have occurred had the new accounting policy not been adopted:

($ thousands, except as noted)	**Decrease (increase) in net loss**	**Impact on net cash flows from (used in) operating activities and adjusted funds flow[1]**
Production and operating expense	93	93
General and administrative expense	335	335
Depletion and depreciation expense	(384)	–
Cash interest on lease liabilities	(189)	(189)
Net IFRS 16 implementation impact	**(145)**	**239**

(1) See Non-GAAP measures in this MD&A.

Further information about changes to accounting policies resulting from the adoption of IFRS 16 can be found in Note 3 to the consolidated financial statements.

New standards issued but not yet adopted

In October 2018, the International Accounting Standards Board ("IASB") issued amendments to the definition of a business in IFRS 3 Business Combinations. The amendments are intended to assist entities in determining whether a transaction should be accounted for as a business combination or as an asset acquisition. IFRS 3 continues to adopt a market participant's perspective to determine whether an acquired set of activities and assets is a business. The amendments clarify the minimum requirements for a business; remove the assessment of whether market participants are capable of replacing any missing elements; add guidance to help entities assess whether an acquired process is substantive; narrow the definitions of a business and of outputs; and introduce an optional fair value concentration test.

The amendments to IFRS 3 are effective for annual reporting periods beginning on or after January 1, 2020 and apply prospectively.

CORPORATE GOVERNANCE

The Corporation is committed to maintaining high standards of corporate governance. Each regulatory body, including the Toronto Stock Exchange and the Canadian provincial securities commissions, has a different set of rules pertaining to corporate governance. The Corporation fully conforms to the rules of the governing bodies under which it operates.

RISK FACTORS

The Corporation is exposed to business risks that are inherent in the oil and gas industry, as well as those governed by the individual nature of Perpetual's operations. Risks impacting the business which influence controls and management of the Corporation include, but are not limited to, the following:

- geological and engineering risks;
- the uncertainty of discovering commercial quantities of new reserves;
- commodity prices, interest rate and foreign exchange risks;
- competition; and
- changes to government regulations including shut-in of gas over bitumen assets, royalty regimes and tax legislation.

Perpetual manages these risks by:

- attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the Corporation;
- prudent operation of oil and natural gas properties;
- employing risk management instruments and policies to manage exposure to volatility of commodity prices, interest rates and foreign exchange rates;
- maintaining a flexible financial position;
- maintaining strict environmental, safety and health practices; and
- active participation with industry organizations to monitor and influence changes in government regulations and policies.

A complete discussion of risk factors is included in the Corporation's 2019 Annual Information Form ("AIF") available on the Corporation's website at www.perpetualenergyinc.com or on SEDAR at www.sedar.com.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Perpetual's CEO and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICOFR") as defined in National Instrument 52-109 Certification of Disclosure in Issuer's Annual and Interim Filings in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS.

Disclosure controls and procedures

The DC&P have been designed to provide reasonable assurance that material information relating to Perpetual is made known to the CEO and CFO by others, and that information required to be disclosed by Perpetual in its annual filings, interim filing or other reports is filed or submitted by Perpetual under securities legislation.

Perpetual's CEO and CFO have concluded, based on their evaluation at December 31, 2019, the DC&P are designed and operating effectively to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

Management's annual report on internal controls over financial reporting

Management is responsible for establishing and maintaining adequate ICOFR, which is a process designed by, or under the supervision of, the CEO and CFO, and effected by the board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

Under the supervision and with the participation of management, including the CEO and CFO, an evaluation of the effectiveness of the internal controls over financial reporting was conducted as of December 31, 2019 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2019, the internal controls over financial reporting were designed and operating effectively.

Changes to internal controls over financial reporting

There were no changes in the Corporation's internal control over financial reporting during the three months ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

CEO and CFO certifications

Perpetual's CEO and CFO have filed with the Canadian securities regulators regarding the quality of Perpetual's public disclosures relating to its fiscal 2019 report filed with the Canadian securities regulators.

CRITICAL ACCOUNTING ESTIMATES

Perpetual makes assumptions in applying certain critical accounting estimates that are uncertain at the time the accounting estimate is made and may have a significant effect on the consolidated financial statements. Critical accounting estimates include oil and natural gas reserves, derivative financial instruments, provisions, income taxes, and the amount and likelihood of contingent liabilities. Critical accounting estimates are based on variable inputs including:

- Estimation of recoverable oil and natural gas reserves and future cash flows from reserves;
- Forward market prices;
- Geological interpretations, success or failure of exploration activities, and Perpetual's plans with respect to property and financial ability to hold the property;
- Risk free interest rates;
- Estimation of future abandonment and reclamation costs;
- Facts and circumstances supporting the likelihood and amount of contingent liabilities, including the Sequoia litigation disclosed in Note 8 to the consolidated financial statements; and
- Interpretation of income tax laws.

A change in a critical accounting estimate can have a significant effect on net loss as a result of their impact on the depletion rate, provisions, impairments, losses and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant, and equipment, provisions, derivative financial instruments and accounts payable. A complete discussion of critical accounting estimates is included in the notes to the consolidated financial statements at December 31, 2019.

FORWARD-LOOKING INFORMATION AND STATEMENTS: Certain information and statements contained in this MD&A including management's assessment of future plans and operations and including the information contained under the heading "2020 Guidance" may constitute forward-looking information and statements within the meaning of applicable securities laws. This information and these statements relate to future events or to future performance. All statements other than statements of historical fact may be forward-looking information and statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook", "guidance", "objective", "plans", "intends", "targeting", "could", "potential", "strategy" and any similar expressions are intended to identify forward-looking information and statements.

In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the Company's ability to continue as a going concern; the quantity and recoverability of Perpetual's reserves; the timing and amount of future production; future prices as well as supply and demand for natural gas, crude oil and NGL; the existence, operations and strategy of the commodity price risk management program; the approximate amount of forward sales and financial contracts to be employed, and the value of financial forward natural gas, oil, NGL and other risk management contracts; net income (loss) and adjusted funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes; production and operating, general and administrative, and other expenses; the costs and timing of future abandonment and reclamation, asset retirement and environmental obligations; the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Corporation's asset base; the Corporation's acquisition and disposition strategy and the existence of acquisition and disposition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom; Perpetual's ability to benefit from the combination of growth opportunities and the ability to grow through the capital expenditure program; expected compliance with credit facility and term loan covenants in 2020 and 2021; expected book value and related tax value of the Corporation's assets and prospect inventory and estimates of net asset value; adjusted funds flow; ability to fund exploration and development; the corporate strategy; expectations regarding Perpetual's access to capital to fund its acquisition, exploration and development activities; the effect of future accounting pronouncements and their impact on the Corporation's financial results; future income tax and its effect on adjusted funds flow; intentions with respect to preservation of tax pools and taxes payable by the Corporation; funding of and anticipated results from capital expenditure programs; renewal of and borrowing costs associated with the credit facility; future debt levels, financial capacity, liquidity and capital resources; future contractual commitments; drilling, completion, facilities, construction and waterflood plans, and the effect thereof; the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other issuers; Crown royalty rates; Perpetual's treatment under governmental regulatory regimes; business strategies and plans of management including future changes in the structure of business operations and debt reduction initiatives; and the reliance on third parties in the industry to develop and expand Perpetual's assets and operations.

The forward-looking information and statements contained in this MD&A reflect several material factors, expectations and assumptions of the Corporation including, without limitation, that Perpetual will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing, and in certain circumstances, the implementation of proposed tax, royalty and regulatory regimes; the ability of Perpetual to obtain equipment, services, and supplies in a timely manner to carry out its activities; the accuracy of the estimates of Perpetual's reserve and resource volumes; the timely receipt of required regulatory approvals; certain commodity price and other cost assumptions; the timing and costs of storage facility and pipeline construction and expansion and the ability to secure adequate product transportation; the continued availability of adequate debt and/or equity financing and adjusted funds flow to fund the Corporation's capital and operating requirements as needed; and the extent of Perpetual's liabilities.

The Corporation believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this MD&A are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation: volatility in market prices for oil and natural gas products; supply and demand regarding Perpetual's products; risks inherent in Perpetual's operations, such as production declines, unexpected results, geological, technical, or drilling and process problems; unanticipated operating events that can reduce production or cause production to be shut-in or delayed; changes in exploration or development plans by Perpetual or by third party operators of Perpetual's properties; reliance on industry partners; uncertainties or inaccuracies associated with estimating reserves volumes; competition for, among other things; capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance; increased costs; incorrect assessments of the value of acquisitions; increased debt levels or debt service requirements; industry conditions including fluctuations in the price of natural gas and related commodities; royalties payable in respect of Perpetual's production; governmental regulation of the oil and gas industry, including environmental regulation; fluctuation in foreign exchange or interest rates; the need to obtain required approvals from regulatory authorities; changes in laws applicable to the Corporation, royalty rates, or other regulatory matters; general economic conditions in Canada, the United States and globally; stock market volatility and market valuations; limited, unfavorable, or a lack of access to capital markets, and certain other risks detailed from time to time in Perpetual's public disclosure documents. In addition, defence costs of legal claims can be substantial, even with respect to claims that have no merit and due to the inherent uncertainty of the litigation process, the resolution of the legal proceedings to which the Company has become subject could have a material effect on the Company's financial position and results of operations. The foregoing list of risk factors should not be considered exhaustive.

The forward-looking information and statements contained in this MD&A speak only as of the date of this MD&A, and neither the Corporation nor any of its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, unless expressly required to do so by applicable securities laws.

OIL AND GAS ADVISORIES

This MD&A contains metrics commonly used in the oil and natural gas industry, such as "recycle ratio", "finding and development" costs or "F&D" costs, and "F&D recycle ratio". These oil and gas metrics have been prepared by management and do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in this MD&A to provide readers with additional measures to evaluate Perpetual's performance, however, such measures are not reliable indicators of Perpetual's future performance and future performance may not compare to Perpetual's performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders and investors with measures to compare Perpetual's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this MD&A, should not be relied upon for investment or other purposes.

F&D costs are calculated on a per boe basis by dividing the aggregate of the change in FDC from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category. F&D costs take into account reserve revisions during the year on a per boe basis. The aggregate of the F&D costs incurred in the financial year and changes during that year in estimated FDC generally will not reflect total F&D costs related to reserves additions for that year.

F&D recycle ratio is calculated by dividing the operating netback for the period by the F&D costs per boe for the particular reserve category.