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, 2018 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, 2018 and 2017. 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"). 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 27, 2019.

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 the change in gas over bitumen royalty financing from adjusted funds flow, in order 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 the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition"), which management considers to not be related to cash flow from operating activities. Restructuring costs include employee downsizing costs and surplus office lease obligations. Commencing in the first quarter of 2018, the Company no longer excludes 'exploration and evaluation – geological and geophysical costs' from the calculation of adjusted funds flow as these costs are no longer significant to the Company's business. The calculation of adjusted funds flow for comparative periods has been adjusted to give effect to this change.

Adjusted funds flow per share is calculated using the same weighted average number of shares outstanding used in calculating 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*)	**2018**	2017	**2018**	2017
Net cash flows from operating activities	**5,163**	10,953	**31,525**	19,170
Changes in non-cash working capital	**2,284**	779	**(2,541)**	9,480
Expenditures on decommissioning obligations	**811**	912	**1,969**	2,336
Change in gas over bitumen royalty financing	**(257)**	(337)	**(1,135)**	(2,421)
Payments of restructuring costs	**51**	234	**337**	2,550
Adjusted funds flow	**8,052**	12,541	**30,155**	31,115
Adjusted funds flow per share	**0.13**	0.21	**0.50**	0.54
Adjusted funds flow per boe	**9.22**	11.59	**7.80**	8.63

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

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

($ thousands, except per boe amounts)	Three months ended December 31, 2018	2017	Years ended December 31, 2018	2017
Royalties	**2,283**	2,651	**10,594**	11,973
Production and operating	**4,851**	3,738	**19,229**	16,299
Transportation	**1,489**	1,479	**6,068**	5,051
General and administrative	**3,793**	2,850	**13,630**	11,943
Cash interest expense and income	**2,242**	2,188	**8,707**	8,004
Cash costs	**14,658**	12,906	**58,228**	53,270
Cash costs per boe	**16.79**	11.92	**15.06**	14.78

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 and foreign exchange contracts but excludes any realized gains (losses) resulting from contracts related to the Shallow Gas Disposition. 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 on 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, and as such, any related realized gains or losses are considered part of the Corporation's realized price.

Gas over bitumen revenue, net of payments: Gas over bitumen revenue, net of payments, includes gas over bitumen royalty credits less monthly payments on 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: Perpetual considers operating netback to be an important performance measure as it demonstrates its profitability relative to current commodity prices. Operating netback is calculated by deducting royalties, production and operating costs, and transportation 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.

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, current portion of gas over bitumen royalty financing, TOU share investment, TOU share margin demand loan, revolving bank debt, senior notes, 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 mark-to-market 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 12-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 2018 HIGHLIGHTS

Natural gas prices in Alberta continued to be weak in the fourth quarter of 2018, remaining disconnected from other North American markets that experienced a significant run up in prices from the seasonal increase in demand driven by the early on-set of winter weather. Perpetual's market diversification contract which commenced sales in November 2017, enabled the Company to sell approximately 80% of its natural gas to markets outside of Alberta, resulting in a realized natural gas price that was 2.8 times the AECO Daily Index average price for the fourth quarter. Strong realized natural gas price performance significantly outweighed the impact of deteriorating oil and natural gas liquids ("NGL") pricing experienced during the fourth quarter, with adjusted funds flow of $8.1 million ($0.13/share) exceeding fourth quarter guidance of $5 to $7 million.

Exploration and development expenditures for the fourth quarter of 2018 were $5.6 million and were directed towards the frac and tie-in of one (1.0 net) Wilrich extended reach horizontal ("ERH") natural gas well that was drilled at East Edson in the first quarter of 2018 and the completion and tie-in of the third quarter heavy oil drilling program at Mannville.

Production averaged 9,491 boe/d per day in the fourth quarter, down 19% from the prior year period due to lower natural gas and NGL production resulting from production shut-ins in the fourth quarter of 2018 and the deferral of natural gas capital spending in 2018 to preserve value during the low natural gas price environment in Alberta, with investment weighted to heavy oil drilling and waterflood activities. Production was comparable to the third quarter of 2018, with steady increases through the fourth quarter resulting from the tie-in and ramp up of production in October from the third quarter heavy oil drilling program, the frac and tie-in of the East Edson natural gas well in November, and the re-start of production from the East Edson four well pad in mid-December. The four well pad had been shut-in at the request of the Alberta Energy Regulator ("AER") after the operator of record, Sequoia Resources Corp. ("Sequoia") filed for bankruptcy in March 2018. Perpetual opportunistically shut-in an average 450 boe/d of East Edson production during the fourth quarter 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 incremental realized revenue of $0.07/Mcf while retaining reserves for future production. December average production was 26% above September average production across all products.

Realized revenue was $22.8 million in the fourth quarter, down 11% from the prior year period, due to a 19% decrease in production, partially offset by an 11% increase in realized revenue per boe. Increased realized pricing in the fourth quarter reflected strong market diversification contract performance combined with realized gains on natural gas price derivatives. Sales to the market diversification contract commenced on November 1, 2017 at 35,000 MMBtu/d, increasing to 40,000 MMBtu/d on April 1, 2018 and shifted Perpetual's natural gas price exposure from the AECO market to five NYMEX-based markets through to November 2022. The market diversification contract generated incremental revenue over AECO Daily Index pricing in the fourth quarter of $6.8 million ($1.64/Mcf) and $19.5 million ($1.02/Mcf) for 2018. Realized heavy oil and NGL prices weakened significantly in the fourth quarter, declining 59% and 36% respectively from average third quarter realized prices before recovering in January 2019, due to the decrease in WTI oil prices combined with wider Canadian oil price differentials.

Cash costs were $14.7 million in the fourth quarter, an increase of $1.8 million (14%) over the prior year period due to the increase in higher operating cost heavy oil production, combined with higher general and administrative costs from incentive compensation programs compared to the prior year period.

The net loss for the fourth quarter of 2018 was $0.3 million ($0.01/share) compared to $6.5 million ($0.11/share) in the prior year quarter. The reduction in net loss is mainly due to increased unrealized gains on derivatives associated with the run-up in NYMEX futures prices in the fourth quarter, partially offset by an increased unrealized loss on the Tourmaline Oil Corp. ("TOU") share investment compared to the prior year period.

Net cash flow from operating activities for the fourth quarter ended December 31, 2018, was $5.2 million compared to $11.0 million in the prior year period due to a 19% decrease in production combined with higher general and administrative compensation costs and lower overhead recoveries reflecting lower capital expenditures compared to the prior year period. Changes in non-cash working capital balances contributed $1.5 million of the decrease in net cash flows compared to the prior year period.

Adjusted funds flow for the fourth quarter ended December 31, 2018, was $8.1 million ($0.13/share), down 36% from $12.5 million ($0.21/share) in the prior year period, due to the decrease in production and higher general and administrative costs.

2018 ANNUAL HIGHLIGHTS

Perpetual executed a capital program in 2018 that was funded from adjusted funds flow, with investment weighted to heavy oil drilling and waterflood activities. Effective program execution and strong asset performance resulted in a 2% growth in proved and probable reserves year-over-year. Exploration and development capital spending of $26.5 million (2017 – $73.0 million), resulted in finding and development costs ("F&D") of $5.09/boe (2017 – $6.16/boe) on a proved and probable basis, including changes in future development capital. Combined with an operating netback of $13.79/boe (2017 – $14.35/boe), Perpetual achieved an attractive F&D recycle ratio of 2.7 times (2017 F&D recycle ratio – 2.3 times). Exploration and development capital spending, less proceeds on dispositions net of acquisitions was $15.0 million in 2018, resulting in finding, development and acquisition costs ("FD&A") of $2.43/boe and a proved plus probable FD&A recycle ratio of 5.7 times. The Company added proved plus probable reserves of 5.2 MMboe to replace 134% of 2018 production.

Production in 2018 averaged 10,594 boe/d, an increase of 7% over 9,876/boe in 2017. Production reached peak levels in the first quarter of 2018 and then declined through the spring and summer before increasing during the fourth quarter as drilling at East Edson was deferred pending higher natural gas prices.

Realized revenue was $89.2 million in 2018, up 5% from $85.0 million in 2017 reflecting the 7% increase in annual production, partially offset by a 2% decrease in realized revenue per boe to $23.07/boe in 2018. The reduction in realized revenue was due to lower AECO average pricing in 2018 combined with the absence of higher realized natural gas derivative gains in 2017. Market diversification contract natural gas sales contributed an incremental $1.02/Mcf over the AECO Daily Index average price in 2018 (2017 – $0.06/Mcf) and effectively insulated Perpetual from the 31% year-over-year decline in AECO Daily Index pricing.

Cash costs were $58.2 million in 2018, up $5.0 million (9%) over 2017 cash costs due to the increase in higher operating and transportation cost heavy oil production, including $1.0 million of remediation costs associated with the Mannville produced water pipeline break that occurred in the third quarter of 2018. General and administrative costs increased due to a 47% reduction in overhead recoveries associated with the year-over-year decrease in capital spending. Interest costs increased in 2018 due to higher average debt levels resulting from borrowing in 2017 used to finance the growth-oriented capital program, partially offset by dividends received from the Company's TOU share investment commencing in early 2018.

Net loss for 2018 was $20.4 million ($0.34/share), down from $36.0 million in 2017 ($0.62/share). Net loss from operating activities was $0.7 million for 2018, an improvement of $5.0 million from the prior year as the growth-oriented capital program in 2017 contributed to a 7% year-over-year growth in production. The remaining reduction in net loss compared to 2017 was due to a reduced unrealized loss of $9.6 million in 2018 (2017 – $22.7 million unrealized loss) related to the change in the fair value of the TOU share investment, combined with losses incurred in 2017 to manage the natural gas floor price obligation associated with the Shallow Gas Disposition.

For the year ended December 31, 2018, net cash flow from operating activities was $31.5 million compared to $19.2 million in 2017. Substantially all of the increase in net cash flows was attributable to changes in non-cash working capital balances reflecting lower accounts payable and accrued liability balances at December 31, 2018 compared to the prior year-end, due to the reduction in fourth quarter spending compared to the prior year period.

For the year ended December 31, 2018, adjusted funds flow was $30.2 million ($0.50/share), down $0.9 million (3%) from $31.1 million ($0.54/share) in 2017 as the impact of the 7% year-over-year increase in production was more than offset by lower general and administrative cost recoveries associated with lower capital expenditures incurred in 2018 combined with higher borrowing costs associated with debt incurred to finance higher capital expenditures in 2017.

2019 OUTLOOK

Perpetual's 2019 capital expenditure and adjusted funds flow guidance remains unchanged from guidance released with its 2018 third quarter results on November 7, 2018.

The Company's Board of Directors has approved a total capital spending program of $21 to $25 million for 2019 to be funded from adjusted funds flow. At least 50% will be spent in Eastern Alberta, primarily targeting heavy oil development at Mannville along with abandonment and reclamation work of up to $2 million to prudently address decommissioning obligations associated with non-producing wells. The remaining 50% of expenditures will be concentrated in East Edson, developing liquids-rich natural gas reserves in the Wilrich formation if AECO forward gas prices support investment in the second half of 2019, or alternatively, will be deployed in an expanded heavy oil drilling program. The Company has minimal capital spending planned for the first half of 2019. The second half program is planned to align operations with higher anticipated commodity prices.

Forecast capital activity in Mannville for 2019 includes the drilling of 10 (10.0 net) new wells, targeting a mix of infill wells and step outs in waterflooded pools as well as multi-lateral wells in several pools in Eastern Alberta. Timing for the 2019 program is in the third quarter to take advantage of lower drilling, completion, and equipping costs generally realized in the summer in Mannville. Additionally, up to 10 shallow gas recompletions are planned to be executed in late 2019, if gas prices improve, to partially offset natural gas declines in Eastern Alberta. Decommissioning expenditures will continue to be focused in the Mannville area and are expected to provide future lease rental and property tax expense reductions while maintaining regulatory compliance. In Eastern Alberta, production is forecast to increase by 20% to 30% from 2018, to a range of 2,200 to 2,400 boe/d (61% oil) in 2019.

At East Edson, the Company has budgeted a two (2.0 net) well drilling program to come onstream during the fourth quarter of 2019, as well as capital for a strategic secondary zone recompletion program and maintenance. The two wells will be extended reach horizontal ("ERH") wells, as the performance of the ERH wells drilled in late 2017 and early 2018 indicate improved capital efficiencies over the wells drilled with less than 2,500 meters of lateral length. If AECO forward gas prices normalize above $2.00/Mcf, drilling activities are expected to continue into 2020. Processing capacity at the Company's 100% working interest and operated West Wolf Lake facility is 65 MMcf/d, with an additional 13 MMcf/d of working interest capacity at the non-operated Rosevear plant, plus associated liquids. The planned drilling will not have a material impact on production in 2019, as new wells are forecast to come on stream late in the year. Natural declines and capital spending deferrals to late 2019 result in lower anticipated 2019 production in East Edson with an average of 7,000 to 7,200 boe/d (10% oil and NGL). Despite reduced production in East Edson and a substantially fixed operating cost base, operating costs are forecast to remain low in 2019, at less than $3.25/boe.

The table below summarizes anticipated capital spending and drilling activities for the first and second half of 2019.

2019 Exploration and Development Forecast Capital Expenditures

	H1 2019 (*$ millions*)	**# of wells (*gross/net*)**	**H2 2019 (*$ millions*)**	**# of wells (*gross/net*)**
West Central liquids-rich gas	0	0/0.0	12	2/2.0
Eastern Alberta	0	0/0.0	11	10/10.0
Total[(1)]	**0**	**0/0.0**	**23**	**12/12.0**

(1) Excludes budgeted abandonment and reclamation spending of $1.5 to $2.0 million in 2019.

Perpetual is targeting a 2019 capital program that is funded by adjusted funds flow. Perpetual forecasts average production of 9,200 to 9,600 boe/d, with oil and NGL production growing to represent more than 20% of the production mix. This represents a reduction in average daily production in 2019 of 10% to 15% relative to 2018, but includes a 17% increase in average oil and NGL production. The Company expects to exit the year at over 11,500 boe/d (approximately 80% natural gas) as production ramps up again in the fourth quarter driven by the second half capital spending program targeting seasonal natural gas price optimization.

Cash costs of $17.00 to $18.00/boe are forecast for 2019, up approximately 13% to 16% from 2018 due to the impact of lower forecast 2019 production at East Edson on a substantially fixed operating cost base. The increase in higher netback and higher operating cost oil production in 2019 is also expected to contribute to the increase in 2019 cash costs per boe.

Perpetual has diversified its commodity and natural gas pricing point exposure (net of royalties) away from AECO as detailed below:

Market/Pricing Point

Natural gas	**Estimated 2019 Exposure**
AECO(1)	–
AECO - fixed price	2%
Empress	7%
Dawn	15%
Michcon	10%
Chicago	24%
Malin	21%
Total natural gas	79%
Natural gas liquids – Condensate(1)	4%
Natural gas liquids – Other(1)	2%
Crude oil(1)(2)	15%
Total	100%

(1) Net of royalties.
(2) For the 2019 calendar year, Perpetual has a costless collar on 500 bbl/d protecting a WTI floor price of US$60.00/bbl with a ceiling price of US$72.40/bbl, along with a 750 bbl/d WCS differential fixed at US$25.22/bbl.

Guidance assumptions are as follows:

	2019 Guidance
Exploration and development expenditures (*$ millions*)	**$21 - $25**
2019 cash costs (*$/boe*)	**$17.00 - $18.00**
2019 average daily production (*boe/d*)	**9,200 – 9,600**
2019 average production mix (*%*)	**20% - 24% oil and NGL**

Commodity price assumptions reflect market price levels as follows:

	2019 Guidance
2019 average NYMEX natural gas price (*US$/MMBtu*)	**$2.99**
2019 average West Texas Intermediate ("WTI") oil price (*US$/bbl*)	**$56.56**
2019 average Western Canadian Select ("WCS") differential (*US$/bbl*)	**($15.88)**
2019 average exchange rate (US$1.00 = Cdn$)	**$1.34**

Year-end 2019 net debt (net of the estimated market value of the Company's TOU share investment of approximately $34 million), is forecast at $107 to $113 million, a marginal increase from guidance provided with Perpetual's third quarter earnings release of $104 to $107 million. Estimated mid-range guidance for the 2019 year-end net debt to trailing twelve months adjusted funds flow ratio is forecast at approximately 4.5 times. Current guidance is based on the following assumptions:

- Net debt at December 31, 2018 of $112.6 million
- Adjusted funds flow for 2019 of $22 to $27 million ($0.36/share to $0.44/share)
- Capital spending for 2019 of $21 to $25 million
- Decommissioning expenditures for 2019 of $1.5 to $2.0 million

The following sensitivities can be applied to estimate changes to projected 2019 cash flow from operating activities and adjusted funds flow, assuming no change in differentials to Perpetual's market pricing points:

- For every US$0.25/MMBtu increase or decrease in the Calendar 2019 NYMEX Daily Index price, adjusted funds flow increases or decreases by $4.8 million;
- For every US$2.50/bbl increase or decrease in the Calendar 2019 WTI oil price, adjusted funds flow increases or decreases by $1.4 million;
- For every 2.5 MMcf/d increase or decrease in average natural gas production, adjusted funds flow increases or decreases by $1.4 million;
- For every 250 bbl/d increase or decrease in average crude oil and NGL production, adjusted funds flow increases or decreases by $4.2 million; and
- For every $0.05 increase or decrease in the Cdn$/US$ exchange rate, adjusted funds flow increases or decreases by $1.3 million.

On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy of Sequoia, with the Alberta Court of Queen's Bench (the "Court"), against Perpetual. The claim relates to an over two-year-old transaction when, on October 1, 2016, Perpetual closed the Shallow Gas Disposition to an arm's length third party at fair market value at the time after an extensive and lengthy marketing, due diligence and negotiation process. This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and an application to the Court to dismiss all claims has been made on the basis that there is no merit to any of them. Perpetual's Application for Summary Dismissal was heard during the fourth quarter of 2018 (the "Sequoia Litigation"). The Court's decision is anticipated to be received in the second quarter of 2019. Management expects that the Company is more likely than not to be successful in defending against the claim such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in Perpetual's financial statements.

On March 27, 2019, the $55 million Borrowing Limit was confirmed by the Company's lenders and the maturity was extended to November 30, 2020. The Credit Facility will revolve until May 31, 2020 and may be extended for a further 364-day period 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 next Borrowing Limit redetermination is scheduled on or prior to November 30, 2019. As part of the lender's agreement to extend the term of the Credit Facility, a significant shareholder has undertaken to support, if requested by the Company, the refinancing of the $14.6 million unsecured senior notes that mature on July 23, 2019 (the "2019 Senior Notes").

Perpetual had available liquidity at December 31, 2018 of $22.7 million, comprised of an unutilized Borrowing Limit of $8.7 million and the market value of its Tourmaline share investment net of the associated margin demand loan, of $14.0 million.

Perpetual is considering options to repay the 2019 Senior Notes including arranging replacement financing and the sale of its Tourmaline shares or other assets.

2018 CAPITAL EXPENDITURES

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Exploration and development	**5,613**	19,028	**26,535**	72,956
Corporate assets	**4**	19	**353**	79
Capital expenditures	**5,617**	19,047	**26,888**	73,035
Acquisitions	**–**	–	**1,871**	432
Payments (proceeds) on dispositions of oil and gas properties	**(1,285)**	20	**(13,441)**	(910)
Net capital expenditures	**4,332**	19,067	**15,318**	72,557

Exploration and development spending by area

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2018**	2017	**2018**	2017
West Central	**4,235**	17,789	**13,665**	65,130
Eastern	**1,378**	1,239	**12,870**	7,826
Total	**5,613**	19,028	**26,535**	72,956

Perpetual's exploration and development spending in the fourth quarter of 2018 was $5.6 million, consistent with capital spending guidance provided with Perpetual's third quarter earnings release, and 71% lower than the comparative period in 2017. In West Central, capital expenditures of $4.2 million were directed towards the frac and tie-in of one (1.0 net) Wilrich extended reach horizontal ("ERH") natural gas well that was drilled during the first quarter of 2018. The timing of this frac was intended to align high initial production rates with higher anticipated winter natural gas prices. Additional capital was spent on the installation of field compression and a sweetening tower to restore several higher liquids ratio wells back to production in early 2019.

Fourth quarter exploration and development spending of $1.4 million in Eastern Alberta included completion and tie-in costs for three (3.0 net) heavy oil horizontal wells which were drilled during the third quarter, along with a fourth well that was re-entered to add three additional multi-lateral legs at Mannville. Capital was also invested to finish the installation of the one-megawatt electricity generator project at the Mannville plant site which came online in the first week of October. The project is utilizing fuel gas produced from the Mannville gas plant and converting it to electricity to be sold on the grid, effectively increasing the value of natural gas production.

For the year ended December 31, 2018, exploration and development spending was $26.5 million, down 64% from 2017 as the 2018 program was purposefully managed to be funded from adjusted funds flow. The Company added proved plus probable reserves at a finding and development ("F&D") cost including changes in future development capital ("FDC") of $5.09/boe. Compared to the 2018 operating netback of $13.79/boe, the Company achieved an attractive proved plus probable recycle ratio of 2.7 times (2017 – 2.3 times). Exploration and development capital spending, less proceeds on dispositions net of acquisitions was $15.0 million in 2018, resulting in finding, development and acquisition costs ("FD&A") of $2.43/boe and a proved plus probable FD&A recycle ratio of 5.7 times. The Company added proved plus probable reserves of 5.2 MMboe in 2018 to replace 134% of production.

Spending in West Central in 2018 was $13.7 million, and included the drilling, completion and tie-in ("DC&T") of one (1.0 net) Wilrich ERH natural gas well, along with the frac and tie-in of two additional wells which were drilled in the fourth quarter of 2017. Additional spending consisted of maintenance activities associated with reconfiguring equipment for higher NGL recoveries.

Spending in Eastern Alberta in 2018 was $12.9 million, and consisted of a six well (6.0 net) multi-lateral horizontal drilling program and one re-entry adding three laterals to an existing producer, one waterflood injector well conversion, one water disposal well conversion and associated facilities on the Company's Mannville heavy oil properties, along with the relocation of the one-megawatt electricity generator from Panny to the Mannville plant site to convert natural gas to electricity sales.

Acquisitions

For the year ended December 31, 2018, Perpetual spent $1.3 million to acquire the remaining 33% working interest in a Company-operated Mannville heavy oil pool. Oil sands leases in the Panny area were acquired for $0.6 million which are geographically and technically synergistic to the existing Panny pilot project and prospective for cold flow heavy oil in the Bluesky formation.

Dispositions

Proceeds (payments) on dispositions

($ thousands)	Three months ended December 31, **2018**	2017	Years ended December 31, **2018**	2017
Proceeds (payments) on dispositions of oil and gas properties	**1,285**	(20)	**13,441**	910
Proceeds on retained shallow gas marketing arrangements(1)	**–**	–	**–**	869
Payments on retained shallow gas marketing arrangements(1)	**–**	(950)	**(8,540)**	(3,769)
Proceeds (payments) on sale of gas storage facility investment	**–**	25	**–**	(675)
Net proceeds (payments) on dispositions	**1,285**	(945)	**4,901**	(2,665)

Gain (loss) on dispositions

($ thousands)	Three months ended December 31, **2018**	2017	Years ended December 31, **2018**	2017
Proceeds on dispositions of oil and gas properties	**1,285**	(20)	**13,441**	910
Carrying amount of PP&E disposed	**–**	–	**(848)**	(8)
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)**	(20)	**651**	902
Realized gain (loss) on retained shallow gas marketing arrangements(1)	**–**	–	**(874)**	869
Unrealized loss on retained shallow gas marketing arrangements(1)	**–**	(3,954)	**–**	(10,546)
Gain (loss) on disposition of gas storage facility investment	**–**	25	**–**	(675)
Gain (loss) on dispositions	**(90)**	(3,949)	**(223)**	(9,450)

(1) Related to the Shallow Gas Disposition.

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 properties for gross proceeds of $13.4 million and the transfer to the purchaser of $0.5 million in liabilities related to decommissioning obligations, resulting in a net gain on oil and gas properties of $0.7 million.

On October 1, 2016, Perpetual completed the Shallow Gas Disposition whereby 5,900 boe/d of mature shallow gas assets in east central and northeast Alberta were sold for minimal cash consideration, and included retained marketing arrangements whereby the Company provided natural gas floor price protection at $2.58/GJ to the purchaser and retained price participation to the extent average monthly AECO prices exceeded $2.81/GJ on 33,611 GJ/d through to August 31, 2018. The Company entered into marketing arrangements prior to closing to fix the cost of the floor price protection through to March 31, 2018. During the first quarter of 2018, Perpetual fixed the cost of the floor price protection for the remaining period from April 1, 2018 to August 31, 2018 at a cost of $7.6 million. Realized and unrealized gains and losses on these marketing arrangements have been recognized as adjustments to gains and losses on dispositions and included as cash flows from investing activities in the consolidated statement of cash flows. For the year ended December 31, 2018, the Company made total payments of $8.5 million (2017 – $3.8 million) related to the fixed floor price protection, and the retained marketing arrangements have since expired.

Expenditures on decommissioning obligations

During the three months ended December 31, 2018, Perpetual spent $0.8 million (Q4 2017 – $0.9 million) on abandonment and reclamation projects. As part of Perpetual's focus on well and pipeline abandonment and reclamation, three reclamation certificates were received from the AER during the fourth quarter of 2018 (Q4 2017 – six) which will result in the cessation of associated property tax and surface lease expenses. For the year ended December 31, 2018, Perpetual spent $2.0 million (2017 – $2.3 million) on abandonment and reclamation projects and applied for 30 reclamation certificates, compared to 35 received in 2017. Expenditures of $1.5 million to $2.0 million are forecast in 2019, focused in Eastern Alberta under the AER's recently adopted area-based closure approach.

SUMMARY OF QUARTERLY AND ANNUAL NET LOSS

Three months ended December 31,

		2018		2017
	(*$ thousands*)	**(*$/boe*)**	(*$ thousands*)	(*$/boe*)
Realized revenue[(1)]	**22,797**	**26.11**	25,541	23.60
Royalties	**(2,283)**	**(2.61)**	(2,651)	(2.45)
Production and operating expenses	**(4,851)**	**(5.56)**	(3,738)	(3.45)
Transportation costs	**(1,489)**	**(1.71)**	(1,479)	(1.37)
Operating netback[(1)]	**14,174**	**16.23**	17,673	16.33
Unrealized change in fair value of derivatives	**10,885**	**12.47**	(1,729)	(1.60)
Gas over bitumen royalty credit and other	**302**	**0.35**	399	0.37
Exploration and evaluation	**(1,617)**	**(1.85)**	(156)	(0.14)
General and administrative expense	**(3,793)**	**(4.34)**	(2,850)	(2.63)
Share-based payments, non-cash	**(566)**	**(0.65)**	(887)	(0.82)
Depletion and depreciation	**(7,777)**	**(8.91)**	(9,415)	(8.70)
Loss on dispositions	**(90)**	**(0.10)**	(3,949)	(3.65)
Finance expense	**(2,306)**	**(2.64)**	(1,265)	(1.17)
Change in fair value of TOU share investment	**(9,543)**	**(10.93)**	(4,319)	(3.99)
Net loss	**(331)**	**(0.38)**	(6,498)	(6.00)
Net loss per share - basic	**(0.01)**		(0.11)	

Years ended December 31,

		2018		2017
	(*$ thousands*)	**(*$/boe*)**	(*$ thousands*)	(*$/boe*)
Realized revenue[(1)]	**89,199**	**23.07**	85,027	23.59
Royalties	**(10,594)**	**(2.74)**	(11,973)	(3.32)
Production and operating expenses	**(19,229)**	**(4.97)**	(16,299)	(4.52)
Transportation costs	**(6,068)**	**(1.57)**	(5,051)	(1.40)
Operating netback[(1)]	**53,308**	**13.79**	51,704	14.35
Unrealized change in fair value of derivatives	**5,747**	**1.49**	2,550	0.71
Gas over bitumen royalty credit and other	**1,046**	**0.27**	2,460	0.68
Exploration and evaluation	**(2,212)**	**(0.57)**	(3,283)	(0.91)
General and administrative expense	**(13,630)**	**(3.52)**	(11,943)	(3.31)
Share-based payments, non-cash	**(2,573)**	**(0.67)**	(4,310)	(1.20)
Depletion and depreciation	**(34,946)**	**(9.04)**	(33,436)	(9.28)
Loss on dispositions	**(223)**	**(0.06)**	(9,450)	(2.62)
Impairment loss	**(7,200)**	**(1.86)**	–	–
Finance expense	**(10,122)**	**(2.62)**	(7,592)	(2.11)
Change in fair value of TOU share investment	**(9,575)**	**(2.48)**	(22,671)	(6.29)
Net loss	**(20,380)**	**(5.27)**	(35,971)	(9.98)
Net loss per share - basic	**(0.34)**		(0.62)	

(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, 2018 and 2017:

	Three months ended December 31, 2018			Three months ended December 31, 2017		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue(1)	**17,481**	**4,029**	**21,510**	18,458	5,352	23,810
Realized gains on derivatives(2)	**–**	**–**	**1,287**	–	–	1,731
Royalties(3)	**(1,611)**	**(672)**	**(2,283)**	(2,055)	(596)	(2,651)
Production and operating expenses	**(1,598)**	**(3,253)**	**(4,851)**	(1,562)	(2,176)	(3,738)
Transportation costs	**(1,085)**	**(404)**	**(1,489)**	(1,117)	(362)	(1,479)
Total operating netback	**13,187**	**(300)**	**14,174**	13,724	2,218	17,673

	Year ended December 31, 2018			Year ended December 31, 2017		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue(1)	**65,383**	**20,745**	**86,128**	59,900	21,822	81,722
Realized gains on derivatives(2)	**–**	**–**	**3,071**	–	–	3,305
Royalties(3)	**(8,156)**	**(2,438)**	**(10,594)**	(9,430)	(2,542)	(11,973)
Production and operating expenses	**(7,160)**	**(12,069)**	**(19,229)**	(7,721)	(8,578)	(16,299)
Transportation costs	**(4,616)**	**(1,452)**	**(6,068)**	(3,408)	(1,644)	(5,051)
Total operating netback	**45,451**	**4,786**	**53,308**	39,341	9,058	51,704

	Three months ended December 31, 2018			Three months ended December 31, 2017		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**7,460**	**2,031**	**9,491**	9,894	1,871	11,765
Total petroleum and natural gas revenue(1)	**25.47**	**21.56**	**24.63**	20.28	31.08	22.00
Realized gains on derivatives(2)	**–**	**–**	**1.48**	–	–	1.60
Royalties(3)	**(2.35)**	**(3.60)**	**(2.61)**	(2.26)	(3.44)	(2.45)
Production and operating expenses	**(2.33)**	**(17.40)**	**(5.56)**	(1.72)	(12.63)	(3.45)
Transportation costs	**(1.58)**	**(2.16)**	**(1.71)**	(1.23)	(2.10)	(1.37)
Total operating netback	**19.21**	**(1.60)**	**16.23**	15.07	12.91	16.33

	Year ended December 31, 2018			Year ended December 31, 2017		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**8,737**	**1,857**	**10,594**	7,896	1,980	9,876
Total petroleum and natural gas revenue(1)	**20.50**	**30.61**	**22.27**	20.84	29.98	22.67
Realized gains on derivatives(2)	**–**	**–**	**0.80**	–	–	0.92
Royalties(3)	**(2.56)**	**(3.60)**	**(2.74)**	(3.27)	(3.53)	(3.32)
Production and operating expenses	**(2.25)**	**(17.81)**	**(4.97)**	(2.68)	(11.88)	(4.52)
Transportation costs	**(1.45)**	**(2.14)**	**(1.57)**	(1.18)	(2.27)	(1.40)
Total operating netback	**14.24**	**7.06**	**13.79**	13.71	12.30	14.35

(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 certain financial prompt month price optimization contracts.
(3) Includes $1.2 million in gross overriding royalty payments at East Edson ("East Edson GORR") for the three months ended December 31, 2018 (Q4 2017 – $1.4 million) and $5.3 million for the year ended December 31, 2018 (2017 – $6.7 million).

For the fourth quarter ended December 31, 2018, operating netback of $14.2 million ($16.23/boe) decreased 20% from $17.7 million ($16.33/boe) in the prior year period due to a 19% decrease in production combined with higher Eastern Alberta operating costs, which were only partially offset by increased realized revenue reflecting the ramp up in NYMEX gas prices during the fourth quarter of 2018. Realized heavy oil and NGL prices weakened significantly in the fourth quarter, declining 59% and 36% respectively from average third quarter realized prices due to the decrease in WTI oil prices combined with significantly wider Canadian oil price differentials, before recovering in January 2019 with the announcement of the Government of Alberta's production curtailments. 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, 2018, Perpetual's operating netback of $53.3 million ($13.79/boe) increased 3% from $51.7 million ($14.35/boe) in 2017. The increase in the 2018 operating netback was due to the strong contribution of the market diversification contract to boost realized revenue despite lower AECO Daily Index prices combined with the 7% increase in year-over-year production. This was partially offset by higher operating costs in Eastern Alberta related to the repair and cleanup costs from the Mannville pipeline break, combined with the increase in higher operating cost heavy oil production.

Production

	Three months ended December 31,		Years ended December 31,	
	2018	2017	**2018**	2017
Natural gas (*MMcf/d*)				
Eastern	**4.6**	6.0	**5.1**	6.3
West Central	**40.3**	54.8	**47.5**	43.3
Total natural gas(1)	**44.9**	60.8	**52.6**	49.6
Crude oil (*bbl/d*)				
Eastern(2)	**1,265**	869	**1,020**	929
West Central	**36**	19	**30**	19
Total crude oil	**1,301**	888	**1,050**	948
Total NGL (*bbl/d*)(3)	**715**	738	**774**	655
Total production (*boe/d*)	**9,491**	11,765	**10,594**	9,876

(1) Natural gas production yields a higher heat content (GJ/Mcf), resulting in higher realized natural gas prices. See "Commodity Prices" – Average Perpetual prices for selling price premium to AECO Daily Index.
(2) Primarily Mannville heavy oil.
(3) Primarily West Central liquids-rich gas.

Fourth quarter production averaged 9,491 boe/d, down 2,274 boe/d or 19% from the prior year period (Q4 2017 - 11,765 boe/d). Fourth quarter 2018 production was reduced by 5% as Perpetual opportunistically shut-in an average 450 boe/d of East Edson production 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 an increase in realized revenue of $0.3 million ($0.07/Mcf) while retaining reserves for future production. Production increased steadily over the fourth quarter as heavy oil production from the Mannville third quarter drilling program was tied-in. At East Edson, one horizontal well drilled in the first quarter of 2018 was frac'd and tied-in to production mid-way through the fourth quarter, and approximately 700 boe/d of production from a four well pad that was shut-in by the AER was restarted in mid-December. The four well pad had been shut-in since the second quarter at the request of the AER, after the operator of record, Sequoia, filed for bankruptcy. Compared to the third quarter of 2018, production decreased by 1%, but exited with average December production 26% higher than September production.

Fourth quarter natural gas production averaged 40.3 MMcf/d at West Central, a decrease of 26% from the comparative period of 2017. The decrease was driven by natural declines resulting from limited capital investment during 2018 in response to low AECO natural gas prices, in addition to voluntary market related shut-ins of natural gas during the quarter and the four well pad at East Edson which remained shut-in for most of the quarter at the request of the AER.

West Central NGL yields were consistent with the previous quarters in 2018 at approximately 17.7 bbls per MMcf of natural gas, an increase from 13.5 bbls per MMcf in the prior year, due to the reconfiguration of plant processing equipment and higher NGL production from wells tied-in during 2018.

Crude oil production in Eastern Alberta was 46% higher than the fourth quarter of 2017. The increased production was due to the combined impact of the third quarter drills which commenced production in late September and lower base declines at Mannville due to waterflood operations. At Mannville, waterflood performance continues to be a focus with base production increasing by approximately 8% throughout the year. In addition, the Mannville heavy oil working interest acquisition completed in the third quarter of 2018 contributed to higher fourth quarter production compared to the prior year.

For the year ended December 31, 2018, production increased 7% to 10,594 boe/d compared to 9,876 boe/d in the prior year. Production reached peak levels in the first quarter of 2018 and then declined through the spring and summer before increasing in the fourth quarter, as drilling and completions activity at East Edson was deferred pending higher natural gas prices. Average annual natural gas production increased 6% to 52.6 MMcf/d (2017 – 49.6 MMcf/d) and NGL production increased 18% to 774 bbl/d (2017 – 655 bbl/d), reflecting the drilling, completion and tie-in of one (1.0 net) Wilrich ERH natural gas well, along with the frac and tie-in of two additional wells which were drilled in the fourth quarter of 2017. During 2018, Perpetual shut-in an average 200 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 $0.5 million ($0.03/Mcf) while retaining reserves for future production. For the year ended December 31, 2018, crude oil production was 1,050 bbl/d, an increase of 11% from the prior year, due to the same factors mentioned above.

Commodity Prices

	Three months ended December 31,		Years ended December 31,	
	2018	2017	**2018**	2017
Reference prices				
NYMEX Daily Index (US*$/MMBtu*)	**3.64**	2.93	**3.09**	3.11
AECO Daily Index (*$/GJ*)	**1.48**	1.60	**1.42**	2.04
AECO Daily Index *($/Mcf)*(1)	**1.56**	1.69	**1.50**	2.16
Alberta Gas Reference Price (*$/GJ*)(2)	**1.50**	1.62	**1.29**	2.02
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**58.81**	55.40	**64.77**	50.95
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(39.42)**	(12.26)	**(26.31)**	(11.98)
WCS average (*$CAD/bbl*)(3)	**25.59**	54.79	**50.00**	50.66
Average Perpetual prices				
Natural gas (*$/Mcf*)(1)				
AECO Daily Index	**1.56**	1.69	**1.50**	2.16
Heat Content Premium	**0.17**	0.17	**0.16**	0.21
Market Diversification Contract	**1.64**	0.19	**1.02**	0.06
Realized gains (losses) on financial and physical gas derivatives	**0.84**	0.71	**0.26**	0.80
Realized gains (losses) on prompt month price optimization	**0.17**	0.46	**0.11**	0.28
Realized natural gas price (*$/Mcf*)(4)	**4.38**	3.22	**3.05**	3.51
Premium to AECO Daily Index	**281%**	191%	**203%**	163%
Premium to AECO Daily Index due to higher heat content	**11%**	10%	**11%**	10%
Realized oil price (*$/bbl*)(4)	**19.83**	47.30	**40.62**	41.62
Realized natural gas liquids ("NGL") price (*$/bbl*)	**35.73**	54.17	**52.96**	46.60

(1) Converted from $/GJ using a standard 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 = $1.32 for the three months ended December 31, 2018 (Q4 2017 – $1.27) and $1.30 for the year ended December 31, 2018 (2017 – $1.30).
(4) Realized natural gas and oil prices includes 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.

Despite US natural gas production growing by 8.7 Bcf/d from 2017 to 2018, 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 only 1% from US$3.11/MMBtu in 2017 to an average of US$3.09/MMBtu in 2018. In comparison, the AECO Daily Index prices decreased 30% from $2.04/GJ in 2017 to $1.42/GJ in 2018. During 2018, AECO became disconnected from the North American market as production growth in the Western Canadian Sedimentary Basin has outpaced market access and market demand.

The increase of WTI to US$64.77/bbl in 2018 from US$50.95/bbl in 2017 was related to the gradual reduction in global oil inventories during 2018 as a result of increased global demand of crude by approximately 1.2 MMbbl/d over 2017 levels and the supply restrictions implemented by OPEC effective January 1, 2017 to a target of 1.2 MMbbl/d, along with an additional cut from select non-OPEC producers of up to 0.6 MMbbl/d.

Perpetual's realized natural gas price, including derivatives, increased 36% to $4.38/Mcf in the fourth quarter of 2018 from $3.22/Mcf in the comparative period of 2017, and represented a 281% premium over the AECO Daily Index price compared to a 191% premium in the prior year period. The early onset of winter temperatures in November caused the NYMEX gas price to run up sharply, and provided attractive price management opportunities. Realized gains on financial and physical gas derivatives, along with prompt month price optimization activities added $1.01/Mcf to the realized price in the fourth quarter of 2018 (Q4 2017 – $1.17/Mcf). During the fourth quarter of 2018, the average heat content conversion ratio for Perpetual's natural gas production was 1.17 GJ:1 Mcf, slightly higher than 1.16 GJ:1 Mcf in the comparative period of 2017. Natural gas production from East Edson yields higher heat content gas compared to Perpetual's other production areas. The market diversification contract added an additional $1.64/Mcf (Q4 2017 – $0.19/Mcf) on the relative strength of NYMEX daily index prices compared to AECO. Market diversification contract sales commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018. The contract expires October 31, 2022. Pricing is based on daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) outside of Alberta that more closely track North American NYMEX prices.

Perpetual's realized oil price of $19.83/bbl was 58% lower than the fourth quarter of 2017 and included realized losses on crude oil derivative contracts of $0.1 million ($0.44/bbl) on 750 bbl/d of production. The decrease in realized prices was due to the substantial widening of the WCS differential to US$39.42/bbl from US$12.26/bbl in the fourth quarter of 2017, which far outweighed the 6% increase in WTI benchmark pricing over the same period. In early 2019, WCS differentials have narrowed as increased crude by rail transport volumes and the implementation of the temporary oil production restrictions by the Alberta government have reduced storage volumes and alleviated oil pipeline capacity issues. Realized prices in the fourth quarter of 2017 were reduced by $3.12/bbl associated with realized hedging losses in the period.

Perpetual's realized NGL price for the fourth quarter of 2018 was $35.73/bbl, down 34% from the fourth quarter of 2017, reflecting a decrease in all NGL component prices which were impacted by similar transportation capacity issues that caused the WCS differential to widen. Perpetual's average NGL sales composition for the fourth quarter of 2018 consisted of 58% condensate, comparable to the prior year period (Q4 2017 – 62%).

For the year ended December 31, 2018, Perpetual's realized natural gas price was $3.05/Mcf, down 13% from $3.51/Mcf in 2017, reflecting a 31% decrease ($0.66/Mcf) in AECO Daily Index prices and higher realized gains on derivatives in 2017, which were partially offset by the full year contribution from the market diversification contract in 2018.

For the year ended December 31, 2018, Perpetual's realized oil price was $40.62/bbl, down 2% from $41.62/bbl in 2017 as increased average WTI prices in 2018 were fully offset by wider WCS differentials over the same period.

For the year ended December 31, 2018, Perpetual's realized NGL price was $52.96/bbl, up 14% from $46.60/bbl in 2017, correlating with the 27% increase in WTI prices over the comparable period. Approximately 60% of Perpetual's NGL production is comprised of condensate which typically tracks light oil prices.

Revenue

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2018**	2017	**2018**	2017
Petroleum and natural gas ("P&NG") revenue				
Natural gas(1)	**16,734**	16,009	**54,769**	54,444
Oil(1)	**2,427**	4,122	**16,390**	16,139
NGL	**2,349**	3,679	**14,969**	11,139
Total petroleum and natural gas revenue	**21,510**	23,810	**86,128**	81,722
Realized gains on derivatives(2)	**1,287**	1,731	**3,071**	3,305
Realized revenue	**22,797**	25,541	**89,199**	85,027
Unrealized gains (losses) on derivatives	**10,885**	(1,729)	**5,747**	2,550
Total revenue	**33,682**	23,812	**94,946**	87,577
Realized revenue *($/boe)*	**26.11**	23.60	**23.07**	23.59
Total revenue *($/boe)*	**38.57**	22.00	**24.55**	24.29

(1) Includes revenues related to physical forward sales contracts which settled during the period.
(2) Includes realized gains on financial derivatives and certain financial prompt month price optimization contracts.

Realized revenue was $22.8 million in the fourth quarter of 2018, down 11% from the prior year period due to the 19% decrease in production, partially offset by an 11% increase in realized revenue per boe. Included in realized revenues in the fourth quarter of 2018 were $1.3 million in realized gains on derivatives, comprised of $1.4 million of gains on natural gas hedges, partially offset by $0.1 million of losses on WTI and WCS differential hedges.

For the year ended December 31, 2018, realized revenue was $89.2 million, up 5% from the prior year as a result of the 7% increase in production, offset by a 2% decrease in realized revenue per boe. Included in realized revenues for the 2018 year were $3.1 million in realized gains on derivatives comprised of $3.9 million of gains on natural gas hedges, partially offset by $0.8 million of losses on WTI and WCS differential hedges.

Natural gas revenue, before derivatives, of $16.7 million in the fourth quarter of 2018 comprised 78% (Q4 2017 – 67%) of total P&NG revenue while natural gas production was 78% (Q4 2017 – 86%) of total production. Natural gas revenue increased 5% from $16.0 million in the fourth quarter of 2017, reflecting higher realized natural gas prices which more than offset the impact of the 26% decrease in natural gas production volumes driven by natural declines following limited capital investment in 2018. Perpetual's market diversification contract contributed $6.8 million of incremental revenue ($1.64/Mcf) over the AECO Daily Index price in the quarter ($19.5 million and $1.02/Mcf for the year ended December 31, 2018). For the year ended December 31, 2018, natural gas revenue increased by 1% compared to the prior year period, due primarily to the 6% increase in natural gas production, offset partially by the decline in realized natural gas prices.

Oil revenue of $2.4 million represented 11% (Q4 2017 – 17%) of total P&NG revenue while oil production was 14% (Q4 2017 – 8%) of total production. Oil revenue was 41% lower than the same period in 2017 due to the 58% decrease in realized oil prices offset partially by the 47% increase in crude oil production. The lower WCS average prices were a function of the 221% increase in WCS differentials compared to the prior year period, more than offsetting the 6% higher WTI US$ benchmark price and the stronger US dollar. For the year ended December 31, 2018, oil revenue increased by 2%, due primarily to the 11% increase in crude oil production, as WCS prices were comparable to the prior year period.

NGL revenue for the fourth quarter of 2018 of $2.4 million represented 11% (Q4 2017 – 16%) of total P&NG revenue while NGL production was just 8% (Q4 2017 – 6%) of total Company production. NGL revenue decreased by 36% over the prior year period while NGL production only declined by 3%, reflecting a 34% decrease in NGL prices compared to the prior year period. For the year ended December 31, 2018, NGL revenue increased by 34% compared to the prior year period, due to the 18% increase in production combined with a 14% increase in realized NGL prices. The increase in production over the year ended December 31, 2017 reflected increased natural gas production at East Edson and higher NGL yields related to process optimization work at the Company's 100% owned and operated gas plant.

Unrealized gains on derivatives of $10.9 million were recorded in the fourth quarter of 2018. 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

(*$ thousands, except as noted*)	Three months ended December 31, **2018**	2017	Years ended December 31, **2018**	2017
Crown	**496**	260	**2,497**	2,066
Freehold and overriding(1)	**1,787**	2,391	**8,097**	9,907
Total	**2,283**	2,651	**10,594**	11,973
Crown (*% of P&NG revenue*)	**2.3**	1.1	**2.9**	2.5
Freehold and overriding (*% of P&NG revenue*)	**8.3**	10.0	**9.4**	12.1
Total (*% of P&NG revenue*)	**10.6**	11.1	**12.3**	14.6
$/boe	**2.61**	2.45	**2.74**	3.32

(1) Includes $1.2 million in gross overriding royalty payments at East Edson for the three months ended December 31, 2018 (Q4 2017 – $1.4 million) and $5.3 million for the year ended December 31, 2018 (2017 – $6.7 million).

Royalty expense for the fourth quarter of 2018 was $2.3 million, representing 10.6% of total petroleum and natural gas revenue, down from $2.7 million and 11.1% respectively, in the prior year period. Lower royalty rates reflect the decrease 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. The increase in the fourth quarter 2018 realized natural gas price was due to sales priced outside of the Alberta market through the market diversification contract and through realized derivative settlements which are not subject to Alberta crown and overriding royalties. At East Edson, the gross overriding royalty is equivalent to a maximum 5.6 MMcf/d of natural gas and associated NGL production.

On an annual basis, royalty expenses for 2018 were $10.6 million, representing a 16% decrease in the effective combined average royalty rate on P&NG revenue to 12.3% from 14.6% in 2017. Average crown royalty rates increased to 2.9% in 2018 compared to 2.5% in 2017, due primarily to the impact of higher oil prices which more than offset the reduction in Alberta Gas Reference Prices year-over-year. Freehold and overriding royalties decreased as a percentage of P&NG revenue from 12.1% to 9.4%, as the revenue contributed by the market diversification contract and realized derivative settlements attracted no incremental royalties. In addition, as East Edson production increased in 2018, the fixed nature of the gross overriding royalty resulted in a decreased expense as a percentage of revenue and on a unit-of-production basis, which also contributed to the reduced overriding royalty rate in 2018.

Production and operating expenses

(*$ thousands, except as noted*)	Three months ended December 31, **2018**	2017	Years ended December 31, **2018**	2017
Production and operating expenses	**4,851**	3,738	**19,229**	16,299
$/boe	**5.56**	3.45	**4.97**	4.52

Production and operating expenses increased 30% to $4.9 million in the fourth quarter of 2018 compared to $3.7 million recorded during the same period in 2017 due to increased costs in Eastern Alberta associated with maintenance activities and remediation costs for the Mannville produced water spill that occurred in the third quarter. Remediation work related to the pipeline break was completed in October. Production and operating expenses per boe increased by 61% from the prior year quarter as higher cost Eastern Alberta production comprised 21% of total fourth quarter production compared to 16% in the prior year quarter.

For the full year, production and operating expenses increased 18% to $19.2 million in 2018 compared to $16.3 million in 2017. This increase reflected remediation and additional water hauling costs of $1.0 million incurred from the Mannville produced water spill and the absence of a $0.9 million non-recurring adjustment in the prior year period associated with third party processing facilities that were sold as part of the Shallow Gas Disposition. The additional increase at Eastern Alberta reflected higher well counts and associated pump changes. These increases were offset by strong cost control in West Central where operating costs decreased $0.6 million year-over-year.

Transportation costs

(*$ thousands, except as noted*)	Three months ended December 31, **2018**	2017	Years ended December 31, **2018**	2017
Transportation costs	**1,489**	1,479	**6,068**	5,051
$/boe	**1.71**	1.37	**1.57**	1.40

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 2018, transportation costs were $1.5 million, comparable with the fourth quarter of 2017 as crude oil volumes were transitioned to a sales point closer to production locations, resulting in lower trucking costs in the fourth quarter of 2018. On a unit-of-production basis, company-wide transportation costs increased by 25% from $1.37/boe in the fourth quarter of 2017 to $1.71/boe in the same period of 2018 as firm pipeline capacity was increased in late 2017 and unutilized demand charges were incurred in the 2018 period. Transportation costs averaged $1.58/boe at West Central compared to $2.16/boe for production from Eastern Alberta.

For the year ended December 31, 2018, transportation costs were $6.1 million, an increase of 20% over the same period in 2017, due to the increase in firm natural gas transportation commitments at East Edson to 78 MMcf/d that commenced in December 2017. The Company was not able to mitigate any of its excess firm transportation costs throughout 2018, resulting in higher costs on a unit-of-production basis.

Gas over bitumen

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Gas over bitumen royalty credits	**302**	151	**1,046**	2,116
Change in gas over bitumen royalty financing(1)	**(257)**	(337)	**(1,135)**	(2,421)
Gas over bitumen revenue, net of payments	**45**	(186)	**(89)**	(305)
$/boe	**0.05**	(0.17)	**(0.02)**	(0.08)

(1) At December 31, 2018, the fair value of the remaining gas over bitumen royalty financing obligation is estimated to be $1.1 million (2017 – $2.7 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. During 2018, Perpetual recorded $1.0 million in gas over bitumen revenue; a decrease of 51% ($1.1 million) from 2017 attributable to the 36% decrease in Alberta Gas Reference Prices, combined with the annual 10% decline in deemed production.

Gas over bitumen royalty credits earned throughout 2018 were offset by payments of $1.1 million (2017 – $2.4 million) in relation to the 2014 monetization of Perpetual's future gas over bitumen royalty credits. As part of the gas over bitumen royalty financing arrangement, Perpetual makes monthly payments to the purchaser, which from time to time will vary from the actual gas over bitumen credit received in the period due to timing differences. The monthly 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 was recorded as a financial obligation ("Gas over bitumen royalty financing"); however, the entitlement to future revenue from gas over bitumen royalty adjustments is not recorded as an asset, but as revenue with the passage of time as it is earned. As such, gas over bitumen revenue 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 have been included as a reduction to gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty adjustments. During 2018, the gas over bitumen royalty financing obligation was reduced by $1.6 million, comprised of payments of $1.1 million (2017 – $2.4 million) in addition to an unrealized gain of $0.5 million (2017 – gain of $3.2 million). The gain has been included in non-cash finance expense and represents a decrease in the fair value of the gas over bitumen royalty financing obligation compared to 2017, as a result of lower forecast natural gas reference prices.

Exploration and evaluation ("E&E") expenses

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Lease rentals	**132**	156	**649**	703
Geological and geophysical costs	**–**	–	**78**	(22)
Lease expiries (non-cash)	**1,485**	–	**1,485**	2,602
Total E&E expense	**1,617**	156	**2,212**	3,283

Exploration and evaluation expense includes lease rentals on undeveloped acreage, geological and geophysical costs and the write-down of carrying costs related to lease expiries. E&E costs of $1.6 million for the three months ended December 31, 2018 were significantly higher than the same period in 2017 due to non-cash write-downs associated with certain P&NG and bitumen leases deemed to no longer be part of Perpetual's future development plans. Lease rental costs for the three months and year ended December 31, 2018 are comparable with the prior year periods.

General and administrative ("G&A") expenses

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Cash G&A expense	**4,246**	3,707	**15,459**	15,377
Overhead recoveries	**(453)**	(857)	**(1,829)**	(3,434)
Total G&A expense	**3,793**	2,850	**13,630**	11,943
Total G&A expense *($/boe)*	**4.34**	2.63	**3.52**	3.31

During the fourth quarter of 2018, cash G&A expense was $4.2 million, a 15% increase from the prior year period of $3.7 million, due primarily to increased incentive compensation costs. Sequoia litigation defence costs, net of insurance recoveries, were $0.1 million in the fourth quarter (2018 – $0.4 million). Fourth quarter 2018 overhead recoveries decreased by 47% relative to the 2017 period when capital spending was over three times higher. On a unit-of-production basis, total G&A expense of $4.34/boe for the three months ended December 31, 2018 was up 65% from the prior year period due to the impact of a 19% decrease in production combined with increased total G&A expense.

For the year ended December 31, 2018, total G&A expense increased by 14% over the prior year period, as overhead recoveries declined by 47% in response to the reduction in capital expenditures from $73.0 million in 2017 to $26.9 million in 2018. On a unit-of-production basis, total G&A expense of $3.52/boe for the year ended December 31, 2018 was only up 6% from 2017, as the increase in average daily production helped to mitigate the higher overall costs.

Share-based payments

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Share-based payments expense (non-cash)	**566**	887	**2,573**	4,310
$/boe	**0.65**	0.82	**0.67**	1.20

Non-cash share-based payments expense for the year ended December 31, 2018 decreased $1.7 million compared to the same period in 2017, due to a reduction in the value of outstanding share-based payment awards. New grants of share-based payment awards are typically made during the second quarter; however, the 2018 grants were not made until late in the fourth quarter of 2018, resulting in fewer awards outstanding throughout 2018.

Depletion and depreciation

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Depletion and depreciation	**7,777**	9,415	**34,946**	33,436
$/boe	**8.91**	8.70	**9.04**	9.28

Perpetual recorded $34.9 million of depletion and depreciation expense for the year ended December 31, 2018, up 5% from $33.4 million in 2017 due to the 7% increase in 2018 production volumes compared to the prior year. On a per boe basis, 2018 depletion and depreciation expense of $9.04/boe was 3% lower than the prior year, due primarily to the lower depletion rates associated with the Company's West Central assets, which make up a larger percentage of Perpetual's total production on which depletion expense is recorded. The Company's 2018 capital program added proved plus probable reserves that replaced 134% of 2018 production at F&D costs of $5.09/boe which also contributed to lower depletion rates in 2018 compared to the prior year.

Impairment

For the year ended December 31, 2018, the Company assessed impairment indicators for the Company's cash generating units ("CGUs"). For the years ended December 31, 2018 and 2017, there was no impairment or impairment reversal recognized with respect to the Company's property, plant and equipment ("PP&E").

E&E assets are tested for impairment when there is an indication that a particular project may be impaired. Examples of indicators of impairment include the decision to no longer pursue exploration and development of undeveloped lands, an expiry of the rights to explore in an area, or failure to receive regulatory approval. In addition, E&E assets are assessed for impairment upon their reclassification to producing assets (oil and natural gas interests in PP&E). In assessing the impairment of E&E assets, the carrying value of the assets are compared to their estimated recoverable amount and the impairment of E&E assets is recognized in the consolidated statements of loss and comprehensive loss.

During 2018, Perpetual determined that no additional capital would be spent to hold existing leases on its Waskahigan Duvernay prospect. As a result, the carrying value of the Waskahigan area was written down to its estimated recoverable amount of $1.3 million, resulting in an impairment charge of $7.2 million on E&E assets for the year ended December 31, 2018. On November 1, 2018, Perpetual sold its Waskahigan area interests to a third party for cash consideration of $1.3 million and retained a 1% gross overriding royalty on undeveloped lands sold to maintain exposure to future drilling conducted by the purchaser.

Finance expenses

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Cash interest				
Interest on revolving bank debt	**633**	314	**2,226**	1,078
Interest on TOU share margin demand loan	**130**	227	**570**	687
Interest on term loan	**936**	892	**3,665**	2,441
Interest on senior notes	**710**	755	**2,864**	3,798
Dividend income from TOU share investment	**(167)**	–	**(618)**	–
Total cash interest expense and income	**2,242**	2,188	**8,707**	8,004
Non-cash finance expense				
Amortization of debt issue costs	**262**	198	**1,026**	620
Accretion on decommissioning obligations	**216**	204	**841**	775
Change in fair value of gas over bitumen royalty financing	**(414)**	(1,325)	**(452)**	(3,184)
Change in fair value of TOU share put option margin loans	**–**	–	**–**	1,377
Total non-cash finance expense	**64**	(923)	**1,415**	(412)
Finance expenses recognized in net loss	**2,306**	1,265	**10,122**	7,592

Total cash interest expense was $2.2 million in the fourth quarter of 2018, comparable to the prior year period as increased interest expense on the reserve-based revolving credit facility and term loan associated with higher average borrowing levels, was offset by lower interest on the TOU share margin demand loan, combined with dividend income from the Company's TOU share investment which commenced early in 2018. Total cash interest expense for the 2018 year was $8.7 million, up $0.7 million from 2017 due to increased year-over-year debt levels compared to 2017, partially offset by dividend income of $0.6 million (2017 – nil) received from the TOU share investment.

Total non-cash finance expense for the three months ended December 31, 2018 was $0.1 million (Q4 2017 – income of $0.9 million). A decrease in the fair value of the gas over bitumen royalty financing was recorded in both periods due to lower AECO future natural gas prices, resulting in a fair value at December 31, 2018 of $1.2 million (December 31, 2017 – $2.7 million). For the year ended December 31, 2018, non-cash finance expense was $1.4 million compared to income of $0.4 million in 2017. This change was again caused by a decrease in the fair value of the gas over bitumen royalty financing, however the decline was considerably larger in 2017 compared to 2018.

The change in fair value of TOU share put option margin loans did not re-occur in 2018, as these loans were refinanced without embedded put option derivatives during the third quarter of 2017.

Change in fair value of TOU share investment

During 2018, the Company recorded an unrealized loss of $9.6 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, 2017 ($22.78 per share) to December 31, 2018 ($16.98 per share). At December 31, 2018, Perpetual owned 1.66 million TOU shares (December 31, 2017 – 1.67 million shares) having a fair market value of $28.1 million (December 31, 2017 – $38.0 million).

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Perpetual's strategy includes maintaining 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, declines in the fair value of the Company's investment in TOU shares, 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, TOU share margin demand loan and net working capital, with value and liquidity enhanced through the ownership of TOU shares. To manage its capital structure and available liquidity, the Company may from time to time issue equity or debt securities, sell its TOU shares or other 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 longer term financial sustainability.

On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy of Sequoia, with the Alberta Court of Queen's Bench (the "Court"), against Perpetual. The claim relates to an over two-year-old transaction when, on October 1, 2016, Perpetual closed the Shallow Gas Disposition to an arm's length third party at fair market value at the time after an extensive and lengthy marketing, due diligence and negotiation process. This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and an application to the Court to dismiss all claims has been made on the basis that there is no merit to any of them. Perpetual's Application for Summary Dismissal was heard during the fourth quarter of 2018 (the "Sequoia Litigation"). The Court's decision is anticipated to be received in the second quarter of 2019. Management expects that the Company is more likely than not to be successful in defending against the claim such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in Perpetual's financial statements.

On November 7, 2018, the revolving bank debt Borrowing Limit was reduced from $60 million to $55 million by the Company's lenders with the next Borrowing Limit redetermination scheduled on or prior to May 31, 2019. The term of the revolving bank debt was not extended and was set to mature on May 31, 2019.

On March 27, 2019, the $55 million Borrowing Limit was confirmed by the Company's lenders and the maturity was extended to November 30, 2020. The Credit Facility will revolve until May 31, 2020 and may be extended for a further 364-day period 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 next Borrowing Limit redetermination is scheduled on or prior to November 30, 2019. As part of the lender's agreement to extend the term of the Credit Facility, a significant shareholder has undertaken to support, if requested by the Company, the refinancing of the $14.6 million 2019 Senior Notes.

Perpetual had available liquidity at December 31, 2018 of $22.7 million, comprised of an unutilized Borrowing Limit of $8.7 million and the market value of its Tourmaline share investment net of the associated margin demand loan, of $14.0 million.

Perpetual is considering options to repay the 2019 Senior Notes including arranging replacement financing and the sale of its Tourmaline shares or other assets.

Capital Management

(*$ thousands, except as noted*)	**December 31, 2018**	December 31, 2017
Revolving bank debt	**42,561**	31,581
Term loan, principal amount	**45,000**	45,000
TOU share margin demand loan, principal amount	**14,144**	18,490
Senior notes, principal amount	**32,490**	32,490
TOU share investment(1)	**(28,132)**	(37,985)
Net working capital deficiency(2)	**6,543**	16,404
Net debt(2)	**112,606**	105,980
Shares outstanding at end of period (*thousands*)(3)	**60,240**	59,263
Market price at end of period (*$/share*)(3)	**0.20**	1.10
Market value of shares	**12,048**	65,189
Enterprise value(2)	**124,654**	171,169
Net debt as a percentage of enterprise value	**90**	62
Trailing twelve months adjusted funds flow(2)	**30,155**	31,115
Net debt to trailing twelve months adjusted funds flow	**3.7**	3.4

(1) The TOU share investment is based on the December 31, 2018 closing price per the Toronto Stock Exchange ($16.98 per share) and 1.66 million TOU shares held (December 31, 2017 – 1.67 million TOU shares held with a closing price of $22.78 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, 2018, Perpetual had total net debt of $112.6 million, up $6.6 million (6%) from December 31, 2017. The increase is mainly attributable to the $9.9 million reduction in the fair value of TOU shares during 2018.

As at December 31, 2018, 56% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow increased slightly during 2018 to 3.7 times at December 31, 2018 (December 31, 2017 – 3.4 times).

Perpetual maintains credit ratings with Moody's Investors Service ("Moody's") and S&P Global that facilitate access to the high yield bond market to refinance existing debt or raise additional funding if required. On May 9, 2018 and on May 24, 2018, Moody's and S&P Global reduced their corporate credit rating by one notch to Caa2 and CCC respectively, with negative outlooks based on the current maturity of the Company's revolving bank debt (if not extended) and the pending maturity of $14.6 million senior notes in July 2019. Perpetual's corporate credit rating was reduced again on November 15, 2018 by S&P Global by one notch to CCC- with a negative outlook, for similar reasons. On February 14, 2019, Moody's confirmed their previous rating and outlook.

TOU share margin demand loan

At December 31, 2018, Perpetual had a $14.1 million TOU share margin demand loan secured by 1.66 million TOU shares (December 31, 2017 - $18.5 million principal amount). On July 31, 2018, the TOU share margin demand loan was entered into with the same lender, having similar terms and conditions as the previous TOU share margin loan. 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. Perpetual is required to maintain a lending ratio of less than 55% based on the ratio of the TOU share margin demand loan compared to the market value of the pledged TOU shares (the "Lending Ratio"). If at any time the Lending Ratio exceeds 55%, Perpetual is obligated to pay down the TOU share margin demand loan to restore the Lending Ratio to 40%. As at December 31, 2018, the Lending Ratio was 50% of the closing market value of the pledged TOU shares.

During the year ended December 31, 2018, the market value of the Company's 1.66 million TOU shares declined, prompting the Company to voluntarily pay down the TOU share margin demand loan by $4.0 million to maintain the Lending Ratio at less than 55%, funded from revolving bank debt. In addition, Perpetual sold 10,700 TOU shares at $25.97 per share and used the proceeds of $0.3 million to partially repay the TOU share margin demand loan.

The effective interest rate on the TOU share margin demand loan as at year-end 2018 was 3.6%. For the year ended December 31, 2018, if interest rates changed by 1%, with all other variables held constant, the impact on annual interest expense and net loss would be $0.1 million.

In addition to the Lending Ratio requirements, the TOU share margin demand loan is subject to customary non-financial covenants. The Company was in compliance with all TOU share margin demand loan covenants as at December 31, 2018.

Revolving bank debt

As at December 31, 2018, the Company had borrowed $42.6 million (December 31, 2017 – $31.6 million) and issued letters of credit of $3.7 million (December 31, 2017 – $3.9 million) under its reserve-based revolving credit facility (the "Credit Facility"). 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 2.0% and 4.5%. The effective interest rate on the Credit Facility at year-end 2018 was 6.2%. For the period ended December 31, 2018, if interest rates changed by 1% with all other variables held constant, the impact on annual interest expense and net loss would be $0.4 million (2017 – $0.3 million).

On November 7, 2018, the Borrowing Limit on the Credit Facility was reduced from $60 million to $55 million, following a reduction in the Borrowing Limit on May 7, 2018 from $65 million to $60 million, with the next semi-annual Borrowing Limit redetermination scheduled on or prior to May 31, 2019. As the Credit Facility matures in less than one year, it has been presented as a current liability on the consolidated statement of financial position as at December 31, 2018. On March 27, 2019, the $55 million Borrowing Limit was confirmed by the Company's lenders and the maturity was extended to November 30, 2020.

The Credit Facility is secured by general, first lien security agreements covering all of the Company's assets, with the exception of the TOU shares that have been pledged as security for the TOU share margin demand loan and 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.

At December 31, 2018, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term loan

On March 14, 2017, Perpetual entered into the term loan which included the issuance of 5.4 million warrants to purchase common shares.

	December 31, 2018	December 31, 2017
Balance, beginning of period	**$ 43,233**	$ –
Principal amount of term loan issued	**–**	45,000
Value allocated to warrants issued	**–**	(769)
Issue costs	**–**	(1,361)
Amortization of issue costs	**496**	363
Balance, end of year	**$ 43,729**	$ 43,233

The $45.0 million principal amount of the term loan was borrowed by an initial $35.0 million draw on March 14, 2017, and a second $10.0 million draw on October 5, 2017.

The term loan matures on March 14, 2021 and bears interest at 8.1% per annum 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 not repay the term loan prior to the second anniversary thereof, except with payment of a make whole premium.

The term loan has a cross-default provision with the Credit Facility and contains substantially similar provisions and 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, TOU shares secured in favor of the TOU share margin demand loan lenders, and certain lands pledged to the gas over bitumen royalty financing counterparty.

At December 31, 2018, the term loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

			December 31, 2018		December 31, 2017	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 Senior Notes	July 23, 2019	8.75%	**$ 14,572**	**$ 14,536**	$ 14,572	$ 14,476
2022 Senior Notes	January 23, 2022	8.75%(1)	**17,918**	**17,344**	17,918	17,204
			$ 32,490	**$ 31,880**	$ 32,490	$ 31,680

(1) Annual interest rate through to January 23, 2018 was 9.75% and 8.75% thereafter.

The 2022 senior notes bear a fixed rate of 8.75% and have identical covenants and rights as the existing 2019 Senior Notes.

As the 2019 Senior Notes mature in less than one year, they have been presented as a current liability on the consolidated statement of financial position as at December 31, 2018.

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. At any time prior to three years before the senior note maturity date, the Company can redeem up to 35 percent of the principal amount of the senior notes at a premium to face value. Within three years of maturity, the Company may redeem up to 100 percent of the senior notes at a premium to face value. Within one year of maturity, the Company may redeem up to 100 percent of the senior notes at the principal amount.

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. The permitted amount of any restricted payment is limited to:

i) To the extent the Company's Consolidated Debt (defined as the sum of the period end balance of revolving bank debt, the term loan, TOU share margin demand loan and gas over bitumen royalty financing) to trailing twelve months income before interest, taxes, depletion and depreciation and non-cash items ("TTM EBITDA") is less than 3.0 to 1.0 (the "Consolidated Debt Ratio"), the sum of 50 percent of TTM EBITDA from January 1, 2011 to the end of the most recently completed fiscal quarter plus 100 percent of the fair market value of any equity contributions made to the Company during that period less the sum of all restricted payments during that period; and

ii) To the extent the Company's Consolidated Debt Ratio is greater than or equal to 3.0 to 1.0 pro forma for the proposed restricted payment, $50 million plus 100 percent of the fair market value of any equity contributions made to the Company.

At December 31, 2018 the senior notes are presented net of $0.6 million in issue costs which are amortized using a weighted average effective interest rate of 9.6%.

At December 31, 2018, 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, 2018 there were 60.2 million common shares outstanding, net of 0.7 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended December 31, 2018 were 60.4 million (Q4 2017 – 59.3 million) and 60.0 million for the year ended December 31, 2018 (2017 – 58.0 million).

On March 14, 2017, in conjunction with the funding of the term loan, the lender received, for no additional consideration, warrants to purchase common shares of Perpetual at a ratio of 120 warrants for every $1,000 committed under the term loan, resulting in the issuance of 5.4 million warrants. Each warrant entitles the holder to acquire common shares on a one for one basis, at an exercise price equal to a $2.34 per share at any time prior to March 14, 2020. Provided the volume weighted average trading price of the common shares is greater than the exercise price for 60 consecutive calendar days (subject to certain restrictions), Perpetual will have the option to require the warrant holder to exercise all or any portion of the warrants at any time prior to expiry on March 14, 2020.

Further, as part of an equity private placement concurrent with the issuance of the term loan, 5.1 million common shares and 1.1 million additional warrants were issued for proceeds of $9.0 million, of which $8.9 million has been allocated to share capital and $0.1 million to warrants. Directors and officers of Perpetual or entities controlled by them purchased 1.6 million common shares and 0.4 million warrants for proceeds of $2.9 million as part of this private placement.

At March 27, 2019, there were 60.0 million common shares outstanding which is net of 0.9 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 27, 2019**
Share options(1)	**4.7**
Restricted rights	–
Performance share rights(2)	**1.1**
Deferred compensation awards(3)	**5.7**
Warrants(4)	**6.5**
Total	**18.0**

(1) As at December 31, 2018, all outstanding share options have an exercise price that is greater than the closing price of the Company's common shares of $0.20 per share.

(2) Performance share rights that vest, become redeemable at a multiple of the performance share rights granted, dependent upon the achievement of certain performance metrics over the vesting period. As at December 31, 2018, performance multipliers of 0.6 and 1.0 have been assumed for those unvested awards granted in 2017 and 2018, respectively.

(3) As at December 31, 2018, 3.0 million deferred options and 1.2 million performance-based long-term incentive awards have an exercise price that is greater than the closing price of the Company's common shares of $0.20 per share.

(4) As at December 31, 2018, all outstanding warrants have an exercise price that is greater than the closing price of the Company's common shares of $0.20 per share.

Contractual obligations and lease commitments

The Company's minimum contractual obligations and lease commitments over the next five years and thereafter excluding estimated interest payments, at December 31, 2018 are as follows:

	2019	**2020**	**2021**	**2022**	**2023 and thereafter**	**Total**
Contractual obligations						
Accounts payable and accrued liabilities	16,612	–	–	–	–	16,612
Fair value of derivative liabilities	2,299	–	–	–	–	2,299
TOU share margin demand loan, principal amount	14,144	–	–	–	–	14,144
Revolving bank debt, principal amount	42,689	–	–	–	–	42,689
Term loan, principal amount	–	–	45,000	–	–	45,000
Senior notes, principal amount	14,572	–	–	17,918	–	32,490
Gas over bitumen royalty financing	680	286	186	–	–	1,152
Pipeline transportation commitments	3,774	2,639	1,008	1,008	1,008	9,437
	94,770	**2,925**	**46,194**	**18,926**	**1,008**	**163,823**
Lease commitments						
Office leases	962	994	1,055	1,070	2,408	6,489
Vehicle leases	110	85	25	–	–	220
Other leases	38	38	38	19	–	133
Total	**95,880**	**4,042**	**47,312**	**20,015**	**3,416**	**170,665**

The Company anticipates that cash flows including cash flow from operating activities, proceeds from potential future asset dispositions and future disposition of its TOU share investment, and access to credit facilities will provide the required funds to discharge the Company's obligations, carry out exploration and development programs and fund ongoing operations for the foreseeable future.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except where noted)	**Q4 2018**	Q3 2018	Q2 2018	Q1 2018
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)*	**35.73**	56.02	60.77	57.61

($ thousands, except where noted)	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Financial				
Oil and natural gas revenue	23,810	20,026	19,728	18,158
Net loss	(6,498)	(8,082)	(7,219)	(14,172)
Per share – basic	(0.11)	(0.14)	(0.12)	(0.26)
Per share – diluted	(0.11)	(0.14)	(0.12)	(0.26)
Cash flow from (used in) operating activities	10,953	5,778	4,728	(2,289)
Adjusted funds flow(1)	12,541	8,199	5,265	5,110
Per share – basic	0.21	0.14	0.09	0.09
Net capital expenditures				
Capital expenditures	19,047	25,392	4,006	24,590
Net payments (proceeds) on acquisitions and dispositions	970	680	609	163
Net capital expenditures	20,017	26,072	4,615	24,753
Common shares *(thousands)*				
Weighted average – basic and diluted	59,338	59,152	59,045	54,468
Operating				
Daily average production				
Natural gas *(MMcf/d)*	60.8	51.8	45.1	40.7
Oil *(bbl/d)*	888	978	1,049	877
NGL *(bbl/d)*	738	733	665	479
Total *(boe/d)*	11,765	10,330	9,223	8,143
Average prices				
Realized natural gas price *($/Mcf)*(3)	3.22	3.11	3.18	5.04
Realized oil price *($/bbl)*(3)	47.30	43.01	43.91	31.39
Realized NGL price *($/bbl)*	54.17	39.06	44.28	49.70

(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, and realized gains and losses on financial derivatives and foreign exchange contracts.

The Company's oil and natural gas revenues, net loss, cash flow from (used in) operating activities and adjusted funds flow are influenced by commodity prices and production levels. Production levels increased throughout 2017 as net capital expenditures were increased in response to improving commodity prices and following limited capital investment in 2016. Natural gas production levels have decreased during 2018 due to 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. Capital expenditures are typically low during the second quarter when break-up conditions in Alberta reduce access for field activities.

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 acquisitions, 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 26, 2019:

Natural Gas

The Company has open physical and financial natural gas arrangements in place at AECO as summarized in the table below. Settlements on physical sales contracts are recognized in oil and natural gas revenue.

Term	Volumes sold (bought) at AECO (*GJ/d*)	Average price (*$/GJ*)(1)	Market prices (*$/GJ*)(2)	Type of contract
January 2019 – March 2019	7,500	3.61	1.84	Financial
April 2019	7,913	1.65	1.32	Financial
April 2019 – October 2019	10,551	1.74	1.24	Physical
June 2019 – October 2019	5,000	1.23	1.21	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for January, February and March 2019 are based on settled AECO Monthly Index prices. Market prices for subsequent months are based on forward AECO Monthly Index prices as of market close on March 26, 2019.

The following table provides a summary of physical and financial basis differential contracts between AECO and NYMEX trading:

Term	Volumes sold (bought) (*MMBtu/d*)	AECO-NYMEX differential (*US$/MMBtu*)(1)	Market prices (*US$/MMBtu*)(2)	Type of contract
January 2019 – March 2019	7,500	(1.55)	(1.69)	Physical
January 2019 – December 2019	2,500	(1.55)	(1.73)	Physical
April 2019 – October 2019	(5,000)	(1.64)	(1.84)	Physical
May 2019 – December 2019	7,500	(1.50)	(1.75)	Financial
November 2019 – December 2019	10,000	(1.54)	(1.41)	Physical
January 2020 – December 2020	15,000	(1.41)	(1.52)	Financial
January 2020 – December 2020	12,500	(1.41)	(1.52)	Physical
January 2021 – December 2021	5,000	(1.15)	(1.38)	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for January, February and March 2019 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 26, 2019.

Crude Oil

The Company had entered into financial oil sales arrangements in US$ as follows:

Term	Volumes (*bbl/d*)	Floor price (*US$/bbl*)	Ceiling price (*US$/bbl*)	Market prices (*US$/bbl*)(1)	Type of contract
January 2019 – December 2019	500	60.00	72.40	58.18	Financial

(1) Market prices for January and February 2019 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 26, 2019.

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

Term	Volumes (*bbl/d*)	WTI-WCS differential (*US$/bbl*)(1)	Market prices (*US$/bbl*)(2)	Type of contract
January 2019 – December 2019	750	(25.22)	(14.84)	Financial
February 2019	400	(12.65)	(9.65)	Financial
March 2019	450	(9.95)	(9.96)	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 2019 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 26, 2019.

Foreign Exchange

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

Term	**Notional (*US$/month*)**	**Strike rate (*US$/Cdn$*)[(1)]**	**Market prices (*US$/Cdn$*)[(2)]**
January 2019 – March 2019	2,500,000	1.30	1.33
April 2019 – October 2019	2,000,000	1.31	1.34
November 2019 – March 2020	2,000,000	1.29	1.33
April 2020 – October 2020	1,500,000	1.30	1.32

(1) Average price calculated using weighted average price for net open contracts.

(2) Market prices for January and February 2019 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 26, 2019.

Natural Gas Sales Obligations

Natural gas volumes sold pursuant to the Company's five-year market diversification contract which expires October 31, 2022, include a fixed volume obligation of 35,000 MMBtu/d (40,000 MMBtu/d commencing April 1, 2018) delivered to AECO and are priced at daily index prices at each of the five market price points, less transportation costs from AECO to each market price point as follows:

Market/Pricing Point	**Daily sales volume (*MMBtu/d*)**
Chicago	12,200
Malin	10,800
Dawn	8,000
Michcon	5,200
Empress	3,800
Total natural gas sales volume obligation delivered to AECO	**40,000**

SELECTED ANNUAL INFORMATION

($ thousands, except where noted)	**2018**	2017	2016
Financial			
Oil and natural gas revenue	**86,128**	81,722	81,403
Net income (loss)	**(20,380)**	(35,971)	107,149
Per share – basic[1]	**(0.34)**	(0.62)	2.11
Per share – diluted[1]	**(0.34)**	(0.62)	1.98
Cash flow from (used in) operating activities	**31,525**	19,170	(7,136)
Adjusted funds flow	**30,155**	31,115	897
Per share[1][2]	**0.50**	0.54	0.02
Total assets	**335,089**	365,570	361,405
Total long-term liabilities	**101,870**	144,186	97,215
Revolving bank debt	**42,561**	31,581	–
Senior notes, at principal amount	**32,490**	32,490	60,573
Term loan, at principal amount	**45,000**	45,000	–
TOU share margin demand loan, at principal amount	**14,144**	18,490	39,953
TOU share investment	**(28,132)**	(37,985)	(66,343)
Net working capital deficiency	**6,543**	16,404	3,917
Total net debt	**112,606**	105,980	38,100
Net capital expenditures			
Capital expenditures	**26,888**	73,035	14,580
Net payments (proceeds) on acquisitions and dispositions	**(3,030)**	2,422	(5,972)
Net capital expenditures	**23,858**	75,457	8,608
Common shares (*thousands*)[3]			
End of period[4]	**60,240**	59,263	53,421
Weighted average – basic	**60,039**	58,017	50,733
Weighted average – diluted	**60,039**	58,017	54,038
Operating			
Daily average production			
Natural gas (*MMcf/d*)	**52.6**	49.6	74.7
Oil (*bbl/d*)	**1,050**	948	1,058
NGL (*bbl/d*)	**774**	655	614
Total average production (*boe/d*)	**10,594**	9,876	14,128
Average prices			
Realized natural gas price *($/Mcf)*	**3.05**	3.51	2.42
Realized oil price *($/bbl)*	**40.62**	41.62	37.60
NGL price (*$/bbl*)	**52.96**	46.60	35.45
Wells drilled			
Natural gas – gross (net)	**1 (1.0)**	15 (14.4)	4 (4.0)
Crude oil – gross (net)	**6 (6.0)**	4 (3.3)	– (–)
Total – gross (net)	**7 (7.0)**	19 (17.7)	4 (4.0)

(1) Based on weighted average common shares outstanding for the year.
(2) See "non-GAAP measure" in this MD&A.
(3) Common shares and per share amounts have been retroactively adjusted to reflect the consolidation of outstanding common shares on the basis of 20 common shares to one common share on March 24, 2016. Common shares are presented net of shares held in trust.
(4) Reduced by shares held in trust (2018 – 661; 2017 – 447; and 2016 – 260). See "Note 16 to the Audited Consolidated Financial Statements".

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

FUTURE ACCOUNTING PRONOUNCEMENTS

Recently adopted

IFRS 9 "Financial Instruments"
On January 1, 2018, Perpetual adopted IFRS 9 "Financial Instruments" as issued by the IASB. IFRS 9 includes a new classification and measurement approach for financial assets and a forward looking 'expected credit loss' model. The adoption of IFRS 9 did not have a material impact on Perpetual's consolidated financial statements.

IFRS 15 "Revenue from Contracts with Customers"
On January 1, 2018, Perpetual adopted IFRS 15 "Revenue from Contracts with Customers". IFRS 15 establishes a comprehensive framework for determining whether, how much, and when revenue from contracts with customers is recognized. Perpetual's revenue relates to the sale of petroleum and natural gas to customers at specified delivery points at benchmark prices.

Perpetual adopted IFRS 15 using the modified retrospective approach. Under this transitional provision, the cumulative effect of initially applying IFRS 15 is recognized on the date of initial application as an adjustment to retained earnings. No adjustment to retained earnings was required upon adoption of IFRS 15.

Issued but not yet adopted

IFRS 16 "Leases"
The Company will be required to adopt the following new standards and amendments as issued by the IASB. The Company has evaluated the impact on the consolidated financial statements as discussed below.

i) In January 2016, the IASB issued the complete IFRS 16 Leases ("IFRS 16") which replaces IAS 17, Leases. The effective date of IFRS 16 is for annual periods beginning on or after January 1, 2019 and early adoption is permitted. Under IFRS 16, a single recognition and measurement model will apply for lessees which will require recognition of assets and liabilities for most leases. The Company is in the final stages of analyzing identified contracts, developing business and accounting processes, making applicable changes to the Company's internal controls and calculating the impact that the adoption of this standard will have on its financial statements. Perpetual has elected to use the modified retrospective approach upon adoption and elected to apply the optional exemptions for short-term and low-value leases. The actual full impact of adoption will depend on the Company's incremental borrowing rate, lease liabilities and practical expedients applied. However, the Company anticipates that the most significant impact of adopting IFRS 16 will be the recognition of the right-of-use ("ROU") assets and corresponding lease liabilities on its operating leases for office space.

   Upon adoption of IFRS 16, the Company will recognize ROU assets and lease liabilities for all leases identified except for optional exemptions taken. The lease liability will be measured at the present value of the remaining lease payments, discounted using the Company's incremental borrowing rate as at January 1, 2019. The ROU asset will be measured at the amount equal to the lease liability on January 1, 2019 with no impact on retained earnings.

   Adoption of IFRS 16 will also result in an increase to depletion, depreciation and amortization expense due to the recognition of the ROU assets, increase in interest and financing charges, and a decrease to general and administrative and production and operating expenses, as applicable. Cash flow from operating activities will increase as a result of the decrease in general and administrative and production and operating expenses, as applicable, partially offset by interest and financing charges. Cash flow from financing activities will decrease due to the addition of principal payments included in lease payments for former operating leases.

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 environment, 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 2018 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 Chief Executive Officer ("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 filed or submitted by Perpetual under securities legislation.

Perpetual's CEO and CFO have concluded, based on their evaluation at December 31, 2018, the DC&P are effective 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 control over financial reporting was conducted as of December 31, 2018 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, 2018, the internal control over financial reporting was effective.

Changes to internal controls over financial reporting

There were no changes in the Corporation's internal control over financial reporting during the three months and year ended December 31, 2018 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 2018 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, the amount and likelihood of contingent liabilities and income taxes. 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 7 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 income 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, 2018.

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 "Outlook" 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 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, NGL and oil; 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 and other risk management contracts; net income 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 2019 and 2020; the retention of, and benefits to be received from holding the TOU share investment; 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, "F&D recycle ratio", "finding, development and acquisition" costs or "FD&A" costs and "FD&A 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 development and exploration activities in the year by the change in reserves from the prior year for the reserve category. FD&A 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 development and exploration activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category. Both F&D costs and FD&A costs take into account reserves 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 costs both including and excluding acquisitions and dispositions have been presented in this MD&A because acquisitions and dispositions can have a significant impact on ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of our cost structure.

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