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 three months ended March 31, 2019 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's unaudited condensed interim consolidated financial statements and accompanying notes for the three months ended March 31, 2019 as well as the audited consolidated financial statements and accompanying notes for the years ended December 31, 2018 and 2017. The MD&A should be read in conjunction with the Corporation's MD&A for the year ended December 31, 2018, as disclosure which is unchanged from the December 31, 2018 MD&A has not been duplicated herein. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). The Corporation adopted IFRS 16, "Leases" ("IFRS 16"), effective January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section of this MD&A for further information. Readers are referred to the advisories for additional information regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information and Statements" section of this MD&A. The date of this MD&A is May 7, 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 surplus office lease obligations, which management considers to not be related to cash flow from operating activities.

Adjusted funds flow per share is calculated using the same weighted average number of shares outstanding used in calculating 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 March 31,	
($ thousands, except per share and per boe amounts)	**2019**	2018[(1)]
Net cash flows from operating activities	**9,292**	11,198
Changes in non-cash working capital	**(2,841)**	(2,396)
Decommissioning obligations settled	**306**	553
Change in gas over bitumen royalty financing	**(395)**	(439)
Payments of restructuring costs	**–**	185
Adjusted funds flow	**6,362**	9,101
Adjusted funds flow per share	**0.11**	0.15
Adjusted funds flow per boe	**6.90**	7.94

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach, resulting in an increase in net cash flows from operating activities and adjusted funds flow of $0.1 million for the first quarter of 2019. Comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

Available Liquidity: Available Liquidity is defined as Perpetual's reserve-based credit facility borrowing limit (the "Borrowing Limit"), plus 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 its 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.

	Three months ended March 31,	
(*$ thousands, except per boe amounts*)	**2019**	2018[(1)]
Royalties	**3,176**	3,063
Production and operating	**5,320**	4,772
Transportation	**1,531**	1,443
General and administrative	**3,471**	3,311
Cash interest expense and income	**2,310**	2,115
Cash costs	**15,808**	14,704
Cash costs per boe	**17.15**	12.82

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

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 associated with the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition") to Sequoia Resources Corp. ("Sequoia"). Realized revenue, including foreign exchange and the market diversification contract, is used by management to calculate the Corporation's net realized commodity prices, taking into account monthly settlements 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. 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, and transportation costs from realized revenue. Operating netback is also calculated on a per boe basis using production sold for the period. Operating netback on a per boe basis can vary significantly for each of the Company's operating areas.

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, current portion of senior notes, current portion of lease liabilities, revolving bank debt, 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 twelve-month basis.

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

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

FIRST QUARTER 2019 HIGHLIGHTS

Natural gas prices in Alberta continue to remain disconnected from other North American markets, with the AECO Daily Index averaging $2.49/GJ in the first quarter of 2019 compared to an average NYMEX price of US$3.15/MMBtu. Perpetual's market diversification contract which commenced sales in November 2017, enabled the Company to sell approximately 72% of its natural gas production (adjusted for heat content) to markets priced at five pricing hubs outside of Alberta, and provided a 29% uplift over average AECO Daily Index prices during the first quarter (Q1 2018 – 20%).

Exploration and development spending for the first quarter of 2019 was $1.2 million, of which 55% was directed towards the installation of field compression and a sweetening tower in West Central to enable reactivation of higher liquids ratio wells back to production. The remainder was directed towards Eastern Alberta and included the installation of automated leak detection monitoring equipment at several well pads.

Production averaged 10,240 boe/d in the first quarter of 2019, down 20% from the comparable period in 2018. The decrease was driven by natural declines resulting from limited capital investment on the Company's natural gas assets during 2018 to preserve value during this period of depressed natural gas pricing in Alberta. Production was 8% higher than the fourth quarter of 2018, as there were no voluntary market related shut-ins of natural gas during the quarter, and the four well pad that was shut-in by the Alberta Energy Regulator ("AER") until December 2018 was back on production for the entire first quarter.

Realized revenue was $24.24/boe in the first quarter of 2019, 16% higher than the comparative period of 2018 ($20.96/boe). The increase was due largely to the 34% increase in Perpetual's realized natural gas price to $3.54/Mcf and a higher proportion of oil and NGL in the production mix (Q1 2019 – 19%; Q1 2018 – 14%), which more than offset the decline in realized crude oil and NGL prices. Higher realized natural gas prices were the result of a 26% increase in the AECO Daily Index, combined with the positive impact of the Company's market diversification contract which contributed $3.5 million of incremental revenue ($0.77/Mcf) over the AECO Daily Index price in the quarter (Q1 2018 - $2.4 million and $0.41/Mcf). Deliveries to the market diversification contract commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018. The market diversification contract is expected to continue to provide higher natural gas pricing and enhanced risk management through future periods of volatile natural gas prices in Western Canada related to market access constraints.

Cash costs were $17.15/boe in the first quarter of 2019, up 34% compared to the prior year period due to the impact of a 20% decrease in production coupled with an 8% increase in cash costs. Production and operating costs were up by $0.5 million, attributable to a 30% (256 bbl/d) increase in higher cost Eastern Alberta heavy oil production. Royalty rates also increased compared to the prior year period, reflecting the increase in the Alberta Gas Reference Price (12% increase) and the AECO Daily Index price (26% increase) which are used to determine crown royalty and freehold and overriding royalty expense, respectively.

The net loss for the first quarter of 2019 was $4.9 million ($0.08/share), compared to a net loss of $6.5 million ($0.11/share) in the comparative period of 2018. The decrease in net loss from the prior year period was due to the change in fair value of the TOU share investment, which increased by $6.1 million in the first quarter of 2019 compared to a decrease of $1.6 million in the comparative period of 2018. This was partially offset by a $5.8 million reduction in the fair value of derivatives compared to the prior year period, attributable to the reduction in future NYMEX natural gas prices and an increase in future oil prices during the first quarter of 2019. The adoption of IFRS 16 in the first quarter resulted in a nominal change in net loss. See "Recently adopted accounting pronouncements" section of this MD&A.

Cash flow from operating activities in the first quarter of 2019 was $9.3 million ($0.15/share), down $1.9 million from the prior year period of $11.2 million ($0.19/share) due to the impact of the 20% decrease in production, as the changes in fair value of the TOU share investment and derivatives that impacted net loss did not impact cash flow from operating activities.

Adjusted funds flow in the first quarter of 2019 was $6.4 million ($0.11/share), down $2.7 million (30%) from the prior year period of $9.1 million ($0.15/share) due to lower cash flow from operating activities and a $0.4 million change in non-cash working capital. Adjusted funds flow was $6.90/boe in the first quarter of 2019, down 13% from the prior year period of $7.94/boe as the impact of lower production and higher production and operating costs, was only partially offset by a 16% increase in realized revenue per boe.

On March 27, 2019, the $55 million revolving bank debt 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 the refinancing of the $14.6 million senior unsecured notes that mature on July 23, 2019 (the "2019 Senior Notes").

Perpetual's Application for Summary Dismissal of the Sequoia litigation was heard during the fourth quarter of 2018. There were no developments during the first quarter of 2019 concerning this 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. See "Liquidity and Capital Resources" section of this MD&A for additional details.

EARLY REDEMPTION OF 2019 SENIOR NOTES

On May 7, 2019, Perpetual announced it will early redeem the $14.6 million 8.75% senior unsecured notes due July 23, 2019 (the "2019 Senior Notes"), effective June 11, 2019 for $1,000 for each $1,000 principal amount of 2019 Senior Notes (the "Cash Consideration"), or $1,075 principal amount of 8.75% senior unsecured notes due January 23, 2022 (the "2022 Senior Notes"). A significant shareholder of the Company will backstop the Cash Consideration such that the redemption of the $14.6 million 2019 Senior Notes will be fully funded, and result in the issuance of $15.7 million 2022 Senior Notes.

OUTLOOK

Perpetual's 2019 capital expenditure and adjusted funds flow guidance remains unchanged from guidance released with its 2018 year-end results on March 27, 2019.

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.

Forecast capital activity in Eastern Alberta for 2019 includes the drilling of up to 10 (10.0 net) horizontal wells, including several multi-lateral wells, targeting a mix of step outs, exploratory wells, and infill wells in waterflooded pools. Timing for start-up of the 2019 program is dependent on surface lease conditions, but is expected to be in June or early July to take advantage of lower drilling, completion, and equipping costs generally realized in the summer in Eastern Alberta. Decommissioning expenditures will continue to be focused in the Mannville area and are expected to provide future surface 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. 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

	Q1 2019 (***$ millions***)	**# of wells** (***gross/net***)	**Q2 - Q4 2019** (***$ millions***)	**# of wells** (***gross/net***)
West Central liquids-rich gas	0.7	0/0.0	11.3	2/2.0
Eastern Alberta	0.5	0/0.0	10.5	10/10.0
Total(1)	**1.2**	**0/0.0**	**21.8**	**12/12.0**

(1) Excludes budgeted abandonment and reclamation spending of $1.5 to $2.0 million in 2019 (Q1 2019 - $0.3 million).

Perpetual expects the 2019 capital program will be 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 approximately 20% to 24% of the production mix. This represents an expected reduction in average daily production in 2019 of approximately 11% relative to 2018, but includes a 16% increase in oil and NGL production. The Company expects to exit the year at over 11,500 boe/d as natural gas and NGL production ramps up again 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 on a substantially fixed operating cost base. Increased oil production in 2019, which is higher cost compared to natural gas cash costs, 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)	11%
Empress	7%
Dawn	14%
Michcon	9%
Chicago	21%
Malin	18%
Total natural gas	80%
Natural gas liquids - Condensate(1)	3%
Natural gas liquids - Other(1)	2%
Crude oil(1)(2)	15%
Total forecast production, net of royalties	100%

(1) Net of royalties.
(2) See "Commodity price risk management and sales obligations" section of this MD&A for details.

Guidance assumptions are as follows:

	2019 Annual Guidance
2019 exploration and development expenditures (*$ millions*)	$21 - $25
2019 cash costs (*$/boe*)	$17.00 - $18.00
2019 average daily production (*boe/d*)	9,200 – 9,600
2019 average production mix (*%*)	20% - 24% oil and NGL
2019 adjusted funds flow (*$ millions*)	$22 - $27
2019 adjusted funds flow *($/share)*	$0.36 - $0.44

Commodity price assumptions reflect forward market price levels as follows:

Market prices(1)	Current Guidance	Prior Guidance
2019 average NYMEX natural gas price (*US$/MMBtu*)	$2.91	$2.99
2019 average West Texas Intermediate ("WTI") oil price (*US$/bbl*)	$60.65	$56.56
2019 average Western Canadian Select ("WCS") differential (*US$/bbl*)	($14.26)	($15.88)
2019 average exchange rate (US$1.00 = Cdn$)	1.33	1.34

(1) Reflects settled and forward market prices.

Year-end 2019 net debt (net of the estimated market value of the Company's TOU share investment of approximately $35 million), is forecast at $107 - $113 million, consistent with prior 2019 guidance issued on March 27, 2019. Current guidance is based on the following assumptions:

- Net debt at March 31, 2019 of $102.4 million;
- Forecast adjusted funds flow for the remainder of 2019 of $16 to $21 million;
- Forecast capital spending for the remainder of 2019 of $20 to $24 million; and
- Forecast decommissioning expenditures for the remainder of 2019 of $1.2 to $1.7 million.

The following sensitivities can be applied to estimate changes to annualized 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 NYMEX Daily Index price, annualized adjusted funds flow increases or decreases by $4.8 million;
- For every US$2.50/bbl increase or decrease in the WTI light oil price, annualized adjusted funds flow increases or decreases by $1.5 million;
- For every 2.5 MMcf/d increase or decrease in average natural gas production, annualized adjusted funds flow increases or decreases by $1.6 million;
- For every 100 bbl/d increase or decrease in average crude oil and NGL production, annualized adjusted funds flow increases or decreases by $1.8 million; and
- For every $0.05 increase or decrease in the Cdn$/US$ exchange rate, annualized adjusted funds flow increases or decreases by $1.5 million.

FIRST QUARTER FINANCIAL AND OPERATING RESULTS

Capital expenditures

	Three months ended March 31,	
(*$ thousands*)	**2019**	2018
Exploration and development	**1,210**	14,847
Corporate assets	**28**	50
Capital expenditures	**1,238**	14,897
Payments on dispositions of oil and gas properties	–	926
Total	**1,238**	15,823

Exploration and development spending by area

	Three months ended March 31,	
(*$ thousands*)	**2019**	2018
West Central	**668**	8,942
Eastern Alberta	**542**	5,905
Total	**1,210**	14,847

Wells drilled by area

	Three months ended March 31,	
(gross/net)	**2019**	2018
West Central	**-/-**	1/1.0
Eastern Alberta	**-/-**	3/3.0
Total	**-/-**	4/4.0

Perpetual's exploration and development spending in the first quarter of 2019 was $1.2 million, 92% lower than the comparative period in 2018, and consistent with guidance released with its 2018 year-end results on March 27, 2019.

Spending at the East Edson property in West Central Alberta was $0.7 million, and was directed towards the installation of field compression and a sweetening tower to restore several higher liquids ratio wells back to production. The installation of the field compression and sweetening tower was completed in January, resulting in incremental production in Q1 2019 of approximately 300 boe/d.

For the three months ended March 31, 2019, spending in Eastern Alberta was $0.5 million, 91% lower than the comparative period in 2018. Spending included the installation of automated leak detection monitoring equipment at several well pads.

Dispositions

Proceeds (payments) on dispositions

	Three months ended March 31,	
(*$ thousands*)	**2019**	2018
Proceeds on dispositions of oil and gas properties	**–**	3
Payments on retained shallow gas marketing arrangements(1)	**–**	(929)
Net payments on dispositions	**–**	(926)

Loss on dispositions

	Three months ended March 31,	
(*$ thousands*)	**2019**	2018
Proceeds on dispositions of oil and gas properties	**–**	3
Carrying amount of PP&E disposed	**–**	–
Carrying amount of E&E disposed	**–**	–
Carrying amount of ARO disposed	**–**	–
Gain on dispositions of oil and gas properties	**–**	3
Realized loss on retained shallow gas marketing arrangements(1)	**–**	(874)
Loss on dispositions	**–**	(871)

(1) Related to the Shallow Gas Disposition.

The Company did not complete any acquisitions or dispositions during the three months ended March 31, 2019.

Expenditures on decommissioning obligations

During the three months ended March 31, 2019, Perpetual spent $0.3 million (Q1 2018 – $0.6 million) on abandonment and reclamation projects. As part of Perpetual's focus on well and pipeline abandonment and reclamation, four reclamation certificates were received from the AER during the first quarter of 2019 (Q1 2018 – eight reclamation certificates) which will result in the cessation of associated property tax and surface lease expenses. 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. Perpetual plans to abandon up to 30 wells and facilities in 2019 and is targeting receipt of up to 30 reclamation certificates.

Operating netbacks

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

	Three months ended March 31, 2019			Three months ended March 31, 2018[3]		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue [1]	**16,194**	**6,005**	**22,199**	18,989	4,351	23,340
Realized gains on derivatives [2]	**–**	**–**	**142**	–	–	691
Royalties	**(2,602)**	**(574)**	**(3,176)**	(2,579)	(484)	(3,063)
Production and operating expenses	**(1,995)**	**(3,325)**	**(5,320)**	(2,043)	(2,729)	(4,772)
Transportation costs	**(1,084)**	**(447)**	**(1,531)**	(1,128)	(315)	(1,443)
Total operating netback	**10,513**	**1,659**	**12,314**	13,239	823	14,753

	Three months ended March 31, 2019			Three months ended March 31, 2018[3]		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**8,542**	**1,698**	**10,240**	11,076	1,666	12,742
Total petroleum and natural gas revenue[1]	**21.07**	**39.30**	**24.09**	19.05	29.02	20.36
Realized gains on derivatives[2]	**–**	–	**0.15**	–	–	0.60
Royalties	**(3.38)**	**(3.76)**	**(3.45)**	(2.59)	(3.23)	(2.67)
Production and operating expenses	**(2.60)**	**(21.76)**	**(5.77)**	(2.05)	(18.20)	(4.16)
Transportation costs	**(1.41)**	**(2.93)**	**(1.66)**	(1.13)	(2.10)	(1.26)
Total operating netback	**13.68**	**10.85**	**13.36**	13.28	5.49	12.87

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

Perpetual's operating netback of $12.3 million ($13.36/boe) in the first quarter of 2019 decreased 17% from $14.8 million ($12.87/boe) in the comparative period of 2018. This decrease was due to the 20% decrease in production caused by natural declines at the East Edson property in West Central, combined with increased higher cost Eastern Alberta heavy oil production, and offset partially by the 4% increase in operating netback per boe. The increased operating netback per boe in the first quarter of 2019 reflected a 16% increase in realized revenue per boe due to improved natural gas pricing and a higher percentage of oil and NGL in the production mix, which more than offset lower realized crude oil and NGL prices.

For the first quarter of 2019, royalties, production and operating expense, and transportation costs per boe were higher than the comparative period of 2018 due to the impact of declining production.

Production

	Three months ended March 31,	
	2019	2018
Natural gas (*MMcf/d*)		
Eastern Alberta	**3.5**	4.9
West Central	**46.5**	61.0
Total natural gas[1]	**50.0**	65.9
Crude oil (*bbl/d*)		
Eastern Alberta[2]	**1,113**	857
West Central	**8**	43
Total crude oil	**1,121**	900
Total NGL (*bbl/d*)[3]	**785**	848
Total production (*boe/d*)	**10,240**	12,742

(1) Natural gas production yielded a heat content of 1.17 GJ/Mcf (Q1 2018 – 1.17) for the three months ended March 31, 2019. 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.

First quarter production averaged 10,240 boe/d, down 20% from 12,742 boe/d in the comparative period of 2018, but 8% higher than the fourth quarter of 2018. Production reached peak levels in the first quarter of 2018, and then declined through the spring and summer before increasing in the fourth quarter due to completion activity at the East Edson property in West Central, combined with the resumption of shut-in production from a four well pad that was re-started in mid-December. West Central production increased from the fourth quarter of 2018 with the full quarter impact of the added production, as well as new volumes brought on from the field compression and sweetener tower project that was completed in mid-January. There were no voluntary market related shut-ins of natural gas production during the first quarter of 2019 (Q1 2018 – nil; Q4 2018 – 450 boe/d).

First quarter natural gas production averaged 46.5 MMcf/d at West Central, down 24% from 61.0 MMcf/d in the comparative period of 2018. Natural gas production was impacted by limited capital investment in West Central throughout 2018, specifically during the second and third quarters when capital investment was deferred in response to low AECO natural gas prices.

NGL yields at East Edson were 16.9 bbls per MMcf in the first quarter of 2019, comparable to the fourth quarter of 2018 but 22% higher than the first quarter of 2018, due to the reconfiguration of plant processing equipment in mid-2018 and higher NGL production from wells tied-in and reactivated during 2018 and the first quarter of 2019.

Crude oil production in Eastern Alberta was 30% higher than the first quarter of 2018. The increased production was due to the combined impact of the 2018 drilling program and lower base declines at Mannville due to waterflood operations. Compared to the fourth quarter of 2018, crude oil production in Eastern Alberta was 12% lower, due to the freeze-off of several wells during February and March caused by extremely cold temperatures in Alberta.

Production at East Edson is expected to decline throughout 2019, prior to new wells from the planned second half drilling program coming on stream late in the year.

Commodity Prices

	Three months ended March 31,	
	2019	2018
Reference prices		
NYMEX Daily Index (*US$/MMBtu*)	**3.15**	3.00
AECO Daily Index (*$/GJ*)	**2.49**	1.97
AECO Daily Index ($/Mcf)(1)	**2.63**	2.08
Alberta Gas Reference Price (*$/GJ*)(2)	**1.88**	1.68
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**54.90**	62.87
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(12.29)**	(24.28)
WCS average (Cdn*$/bbl*)(3)	**56.67**	48.62
Average Perpetual prices		
Natural gas (*$/Mcf*)(1)		
AECO Daily Index	**2.63**	2.08
Heat content premium	**0.29**	0.23
Market diversification contract	**0.77**	0.41
Realized gains (losses) on financial and physical gas derivatives	**(0.04)**	(0.08)
Realized gains (losses) on prompt month price optimization	**(0.11)**	0.01
Realized natural gas price (*$/Mcf*)(4)	**3.54**	2.65
Premium to AECO Daily Index	**135%**	127%
Premium to AECO Daily Index due to higher heat content	**11%**	11%
Realized oil price (*$/bbl*)(4)	**41.12**	48.31
Realized NGL price (*$/bbl*)	**32.16**	57.61

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.
(3) Derived internally using the Bank of Canada average foreign exchange rate of US$1.00 = Cdn$1.33 for the three months ended March 31, 2019 (Q1 2018 – $1.26).
(4) Realized natural gas and oil prices include physical forward sales contracts for which delivery was made during the reporting period, along with realized gains and losses on financial derivatives and foreign exchange contracts.

For the three months ended March 31, 2019, United States production was 8 Bcf/d higher than the comparative period of 2018. Despite the increase in US production, increases in demand from higher liquefied natural gas ("LNG") and Mexican exports caused NYMEX natural gas prices to increase 5% from US$3.00/MMBtu for the three months ended March 31, 2018 to US$3.15/MMbtu in the first quarter of 2019. In comparison, the average AECO Daily Index price increased 26% from $1.97/GJ for the three months ended March 31, 2018 to $2.49/GJ for the three months ended March 31, 2019. The increase in AECO pricing was the result of record-breaking cold weather in Western Canada during February and March that caused significant production freeze-offs in the basin, as well as increased intraprovincial demand requiring large withdrawals from storage to balance the system.

The decrease in WTI to US$54.90/bbl for the three months ended March 31, 2019 from US$62.87/bbl in the comparative period of 2018 was related to concerns over trade issues between the US and China that threatened the overall health of the global economy, in addition to the large build in US crude inventories in Q4 2018 and Q1 2019 resulting from the continued growth in production out of the Permian basin. The WCS differential tightened from an average US$24.28/bbl in the first three months of 2018 to US$12.29/bbl in the same period of 2019, due to Alberta Government apportionments to manage the Western Canadian oversupply situation relative to export capacity, effective January 1, 2019.

Perpetual's realized natural gas price, including derivatives, increased 34% to $3.54/Mcf for the first quarter of 2019 from $2.65/Mcf in the comparative period of 2018, and represented a 135% premium over the AECO Daily Index price compared to 127% in the prior year period. During the first quarter of 2019, the average heat content conversion ratio for Perpetual's natural gas production was 1.17 GJ:1 Mcf, consistent with the comparative period of 2018. Natural gas production from East Edson yields higher heat content gas compared to Perpetual's other production areas. The market diversification contract added $0.77/Mcf (Q1 2018 – $0.41/Mcf) on the relative strength of daily index prices at the five downstream markets compared to the AECO Daily Index. Market diversification contract sales commenced at 35,000 MMBtu/d on November 1, 2017, and increased to 40,000 MMBtu/d on April 1, 2018. Pricing is based on daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) outside of Alberta that generally track North American NYMEX prices. Realized losses on financial and physical gas derivatives, combined with prompt month price optimization operations decreased the realized price in the first quarter of 2019 by $0.15/Mcf (Q1 2018 – $0.07/Mcf).

Perpetual's realized oil price of $41.12/bbl was 15% lower than the first quarter of 2018, and included realized losses on crude oil derivative contracts of $0.9 million ($8.83/bbl) on 1,121 bbl/d of production, as the Government of Alberta apportionments drastically reduced the WCS differential relative to the Company's oil price risk management positions. Realized prices in the first quarter of 2018 were improved by $5.23/bbl associated with realized hedging gains in the period. Compared to the fourth quarter of 2018, realized oil prices in the first quarter increased by $21.29/bbl (107%), driven by a US$27.13/bbl quarter over quarter tightening of the WCS differential.

Perpetual's realized NGL price for the first quarter of 2019 was $32.16/bbl, down 44% from the first quarter of 2018, reflecting a decrease in all NGL component prices which moved lower in concert with lower oil prices. Furthermore, prices for propane and butane have become disconnected from WTI light oil prices in recent months, reflecting excess supply produced from Western Canada and the United States. Perpetual's average NGL sales composition for the first quarter ended March 31, 2019 consisted of 58% condensate, comparable to the prior year period.

Revenue

	Three months ended March 31,	
(*$ thousands, except as noted*)	**2019**	2018
Petroleum and natural gas ("P&NG") revenue		
Natural gas[1]	**14,888**	15,451
Oil	**5,038**	3,490
NGL	**2,273**	4,399
Total petroleum and natural gas revenue	**22,199**	23,340
Realized gains (losses) on derivatives[2]	**142**	691
Realized revenue	**22,341**	24,031
Unrealized gains (losses) on derivatives	**(7,551)**	(2,326)
Total revenue	**14,790**	21,705
Realized revenue *($/boe)*	**24.24**	20.96
Total revenue *($/boe)*	**16.05**	18.93

(1) Includes revenues related to the 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.

Perpetual's petroleum and natural gas ("P&NG") revenue, before derivatives, for the three months ended March 31, 2019 of $22.2 million decreased 5% from the first quarter of 2018, due primarily to the 20% decrease in average daily production, partially offset by higher realized natural gas prices and the higher proportion of oil and NGL in the production mix.

Natural gas revenue, before derivatives, of $14.9 million in the first quarter of 2019 comprised 67% (Q1 2018 – 66%) of total P&NG revenue while natural gas production was 81% (Q1 2018 – 86%) of total production. Natural gas revenue decreased 4% from $15.5 million in the first quarter of 2018, reflecting the impact of the 24% decrease in natural gas production volumes driven by natural declines following limited capital investment in East Edson during 2018. Perpetual's market diversification contract contributed $3.5 million of incremental revenue ($0.77/Mcf) over the AECO Daily Index price in the quarter (Q1 2018 - $2.4 million and $0.41/Mcf).

Oil revenue of $5.0 million represented 23% (Q1 2018 – 15%) of total P&NG revenue while oil production was 11% (Q1 2018 – 7%) of total production. Oil revenue was 44% higher than the same period in 2018, due to the 25% increase in crude oil production which more than offset a 15% decrease in the realized oil price. Compared to the first quarter of 2018, the WCS average price of $56.67/bbl increased by 17%, mainly due to the tightening of the WCS differential by US$11.99/bbl in response to the Alberta government's introduction of production quotas effective January 1, 2019. Perpetual did not fully participate in the improved WCS differential, as hedges were in place protecting a WCS differential of US$25.22/bbl on 750 bbl/d for 2019.

NGL revenue for the first quarter of 2019 was $2.3 million, representing 10% (Q1 2018 – 19%) of total P&NG revenue while NGL production was just 8% (Q1 2018 – 7%) of total Company production. NGL revenue decreased by 48% over the prior year period while NGL production decreased only 7%, reflecting the 44% decrease in Perpetual's realized NGL price compared to the prior year period. Propane and butane prices have become disconnected from WTI light oil prices in recent months, reflecting excess supply produced from Western Canada and the United States. This oversupply condition is expected to continue.

Realized gains on derivatives totaled $0.1 million for the first quarter of 2019, compared to gains of $0.7 million for the same period of 2018. The realized gain in the current period was comprised of $1.0 million from natural gas derivatives (Q1 2018 – $0.3 million gain), largely offset by losses of $0.9 million from oil derivatives (Q1 2018 – $0.4 million gain).

For the first quarter of 2019, Perpetual recorded an unrealized loss on derivatives of $7.6 million (Q1 2018 - $2.3 million unrealized loss). 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. Unrealized losses on derivatives in the first quarter of 2019 were attributable to the impact of lower NYMEX natural gas prices and higher oil prices on derivative positions.

Royalties

($ thousands, except as noted)	Three months ended March 31, 2019	2018
Crown	**513**	801
Freehold and overriding(1)	**2,663**	2,262
Total	**3,176**	3,063
Crown (*% of P&NG revenue*)	**2.3**	3.4
Freehold and overriding (*% of P&NG revenue*)	**12.0**	9.7
Total (*% of P&NG revenue*)	**14.3**	13.1
$/boe	**3.45**	2.67

(1) Includes $1.8 million in gross overriding royalty payments at East Edson for the three months ended March 31, 2019 (Q1 2018 – $1.6 million).

Royalty expenses for the first quarter of 2019 were $3.2 million, 4% higher than the comparative period of 2018 despite both lower production and P&NG revenue. Accordingly, the combined average royalty rate on P&NG revenue increased from 13.1% in the first quarter of 2018 to 14.3% in 2019.

For the three months ended March 31, 2019, higher royalty rates reflect the increase in the Alberta Gas Reference Price (12% increase) and the AECO Daily Index price (26% increase) compared to the prior year period, which are used to determine crown royalty and freehold and overriding royalty expense, respectively. At East Edson, the gross overriding royalty is equivalent to a maximum 5.6 MMcf/d of natural gas and associated NGL production. As East Edson natural gas production has decreased by 24% for the three months ended March 31, 2019 compared to the prior year period, the fixed nature of the gross overriding royalty has resulted in an increased expense on a percentage of revenue and unit-of-production basis.

Production and operating expenses

($ thousands, except as noted)	Three months ended March 31, 2019	2018(1)
Production and operating expenses	**5,320**	4,772
$/boe	**5.77**	4.16

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

Total production and operating expenses were up 39% on a unit-of-production basis to $5.77/boe for the first quarter of 2019, compared to $4.16/boe for the comparable period of 2018. On an absolute dollar basis, production and operating costs were up by $0.5 million, despite the 20% decrease in production, as higher cost Eastern Alberta heavy oil production increased by 30% over the prior year period, comprising 11% of total production in the first quarter. West Central production and operating expenses were essentially flat relative to the first quarter of 2018 at $2.0 million, illustrating the largely fixed cost nature of the East Edson property. On a cost per boe basis, West Central operating costs increased by 27% to $2.60/boe in the first quarter of 2019 (Q1 2018 – $2.05/boe), while Eastern Alberta operating costs increased 19% to $21.76/boe over the same period (Q1 2018 - $18.33/boe) as a result of higher well servicing costs and pump replacements.

Transportation costs

($ thousands, except as noted)	Three months ended March 31, 2019	2018
Transportation costs	**1,531**	1,443
$/boe	**1.66**	1.26

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. Transportation costs in the first quarter of 2019 were $1.5 million, consistent with the prior year period of $1.4 million. Transportation costs averaged $1.41/boe at West Central compared to $2.93/boe for production from Eastern Alberta. On a unit-of-production basis, transportation costs were $1.66/boe in the first quarter, up 32% from the prior year period due to the impact of fixed firm-capacity natural gas transportation costs against lower production. During the first quarter of 2019, the Company was not able to mitigate any of its excess firm transportation costs related to East Edson natural declines attributable to the deferral of development capital spending.

Gas over bitumen

($ thousands, except as noted)	Three months ended March 31, 2019	2018
Gas over bitumen royalty credit	**388**	383
Payments on gas over bitumen royalty financing(1)	**(395)**	(439)
Gas over bitumen, net of payments	**(7)**	(56)
$/boe	**(0.01)**	(0.05)

(1) At March 31, 2019, the fair value of the gas over bitumen royalty financing was estimated to be $1.2 million (December 31, 2018 – $1.1 million).

Perpetual records revenue in relation to gas over bitumen royalty credits received under the Natural Gas Royalty Regulation for natural gas wells which have been shut-in pursuant to shut-in orders issued by the Government of Alberta. During the first quarter of 2019, Perpetual recorded $0.4 million in gas over bitumen revenue, consistent with the same period of 2018. Gas over bitumen revenue was impacted by the 12% increase in Alberta gas reference prices, offset by the annual 10% decline in deemed production.

Gas over bitumen royalty credits earned in the first quarter of 2019 funded payments of $0.4 million (Q1 2018 – $0.4 million) in relation to the 2014 monetization of Perpetual's future gas over bitumen royalty credits. As part of the arrangement, Perpetual makes monthly payments to the purchaser, which from time to time will vary from the actual gas over bitumen royalty credit received in the period due to timing differences. The monthly payment commitment expires concurrent with the gas over bitumen royalty credit, with final expiries 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, entitlement to future revenue from gas over bitumen royalty adjustments are 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 the first quarter of 2019, the gas over bitumen royalty financing obligation was unchanged, comprised of payments of $0.4 million which were fully offset by an unrealized loss of $0.4 million. The loss has been included in non-cash finance expense and represents an increase in the fair value of the gas over bitumen royalty financing obligation caused by higher forecasted natural gas reference prices.

Exploration and evaluation ("E&E") expenses

	Three months ended March 31,	
($ thousands)	**2019**	2018
Lease rentals	**164**	170
Geological and geophysical costs	**–**	–
Lease expiries (non-cash)	**–**	–
Total E&E expense	**164**	170

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. Comparable with the prior year period, Perpetual recorded lease rentals of $0.2 million for the three months ended March 31, 2019.

General and administrative ("G&A") expenses

	Three months ended March 31,	
($ thousands, except as noted)	**2019**	2018(1)
Cash G&A expense	**3,687**	3,914
Overhead recoveries	**(216)**	(603)
Total G&A expense	**3,471**	3,311
$/boe	**3.77**	2.89

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

During the first quarter of 2019, cash G&A expense was $3.7 million, a slight decrease from the prior year period of $3.9 million. Compared to the prior year period, first quarter 2019 overhead recoveries decreased by 64% as a result of deferred exploration and development capital spending, combined with a reduction in expenditures on decommissioning obligations. On a unit-of-production basis, total G&A expense of $3.77/boe for the three months ended March 31, 2019 was up 30% from the prior year period, due to the impact of decreasing production.

Share-based payments

	Three months ended March 31,	
($ thousands, except as noted)	**2019**	2018
Share-based payments expense (non-cash)	**708**	806
$/boe	**0.77**	0.70

Non-cash share-based payments expense for the three months ended March 31, 2019 was $0.7 million, down 12% compared to the same period in 2018 due to a reduction in the value of outstanding share-based payment awards.

Depletion and depreciation

	Three months ended March 31,	
($ thousands, except as noted)	**2019**	2018(1)
Depletion and depreciation	**8,559**	10,124
$/boe	**9.29**	8.83

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

Perpetual recorded $8.6 million of depletion and depreciation expense for the three months ended March 31, 2019, a decrease of 15% from $10.1 million recorded in the prior year period. The decrease reflects the 20% decline in production volumes compared to the prior year period.

Finance expenses

($ thousands)	Three months ended March 31, 2019	2018[1]
Cash interest expense and income		
Interest on revolving bank debt	**683**	468
Interest on TOU share margin demand loan	**121**	148
Interest on term loan	**911**	911
Interest on senior notes	**711**	721
Interest on lease liabilities[1]	**50**	–
Dividend income from TOU share investment	**(166)**	(133)
Total cash interest expense (and income)	**2,310**	2,115
Non-cash finance expense		
Amortization of debt issue costs	**272**	250
Accretion on decommissioning obligations	**215**	207
Change in fair value of gas over bitumen royalty financing	**408**	(130)
Total non-cash finance expense	**895**	327
Finance expenses recognized in net loss	**3,205**	2,442

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

Total cash interest expense (and income) of $2.3 million for the three months ended March 31, 2019 was 9% higher than the prior year period (Q1 2018 – $2.1 million), due to increased interest expense on the reserve-based revolving credit facility associated with higher floating interest rates, partially offset by dividend income of $0.2 million ($0.10 per TOU share) received from the TOU share investment during the first quarter of 2019 (Q1 2018 – $0.1 million).

Total non-cash finance expense for the three months ended March 31, 2019 was $0.9 million (Q1 2018 – $0.3 million). An increase in the fair value of the gas over bitumen royalty financing of $0.4 million was recorded in the first quarter of 2019 due to higher AECO future natural gas prices, resulting in a fair value at March 31, 2019 of $1.2 million.

Change in fair value of TOU share investment

During the three months ended March 31, 2019, Perpetual recorded an unrealized gain of $6.1 million related to the change in fair value of the TOU share investment, which represents the 22% increase in value of TOU shares held from December 31, 2018 ($16.98 per share) to March 31, 2019 ($20.64 per share). At March 31, 2019, the Company owned 1.66 million TOU shares (December 31, 2018 – 1.66 million shares) having a fair market value of $34.2 million (December 31, 2018 – $28.1 million).

LIQUIDITY AND CAPITAL 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 long-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 "Sequoia Litigation"). 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 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.

Capital management

(*$ thousands, except as noted*)	**March 31, 2019**	December 31, 2018[4]
Revolving bank debt	**39,598**	42,561
Term loan, principal amount	**45,000**	45,000
TOU share margin demand loan, principal amount	**14,100**	14,144
Senior notes, principal amount	**32,490**	32,490
TOU share investment[1]	**(34,196)**	(28,132)
Net working capital deficiency[2]	**5,364**	6,543
Net debt[2]	**102,356**	112,606
Shares outstanding at end of period (*thousands*)[3]	**60,037**	60,240
Market price at end of period (*$/share*)	**0.36**	0.20
Market value of shares	**21,613**	12,048
Enterprise value[2]	**123,969**	124,654
Net debt as a percentage of enterprise value	**83**	90
Trailing twelve-months adjusted funds flow[2] [4]	**27,416**	30,155
Net debt to trailing twelve-months adjusted funds flow	**3.7**	3.7

(1) The TOU share investment is based on the March 31, 2019 closing price per the Toronto Stock Exchange ($20.64 per share) and 1.66 million TOU shares held (December 31, 2018 – 1.66 million TOU shares held with a closing price of $16.98 per share).

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

(3) Shares outstanding are presented net of shares held in trust.

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

At March 31, 2019, Perpetual had total net debt of $102.4 million, down $10.2 million (9%) from December 31, 2018. The decrease in net debt was mainly attributable to the $6.1 million increase in the fair value of TOU shares during the first quarter of 2019, combined with net cash flow from operations which exceeded capital expenditures during the period. The net working capital deficiency of $5.4 million at March 31, 2019 decreased by $1.2 million from December 31, 2018, due to reduced capital expenditures during the first quarter of 2019 compared to the fourth quarter of 2018, resulting in lower payables at March 31, 2019 compared to December 31, 2018.

As at March 31, 2019, 61% of net debt outstanding was repayable in 2021 or later. During the three months ended March 31, 2019, Perpetual's net debt to trailing twelve-months adjusted funds flow was unchanged at 3.7 times (December 31, 2018 – 3.7 times).

Perpetual had available liquidity at March 31, 2019 of $31.8 million, comprised of an unutilized revolving bank debt Borrowing Limit of $11.7 million and the market value of its TOU share investment, net of the principal amount of the associated TOU share margin demand loan, of $20.1 million.

TOU share margin demand loan

At March 31, 2019, Perpetual had a $14.1 million TOU share margin demand loan secured by 1.66 million TOU shares (December 31, 2018 - $14.1 million). 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 March 31, 2019, the Lending Ratio was 41% of the closing market value of the pledged TOU shares.

The effective interest rate on the TOU share margin demand loan as at March 31, 2019 was 3.6%. For the period ended March 31, 2019, 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 March 31, 2019.

Revolving bank debt

As at March 31, 2019, the Company had borrowed $39.6 million (December 31, 2018 – $42.6 million) and issued letters of credit of $3.7 million (December 31, 2018 – $3.7 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 March 31, 2019 was 6.3%. For the period ended March 31, 2019, if interest rates changed by 1% with all other variables held constant, the impact on annual interest expense and net income (loss) would be $0.4 million.

On March 27, 2019, the $55 million Borrowing Limit was confirmed by the Company's lenders and the maturity was extended from May 31, 2019 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 the refinancing of the $14.6 million 2019 Senior Notes that mature on July 23, 2019.

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

Term loan

			March 31, 2019		December 31, 2018	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	March 14, 2021	8.1%	**$ 45,000**	**$ 43,861**	$ 45,000	$ 43,729

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

The term loan has a cross-default provision with the Credit Facility and contains substantially similar 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 March 31, 2019, the term loan is presented net of $1.1 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 9.5%.

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

Senior notes

			March 31, 2019		December 31, 2018	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 Senior Notes	July 23, 2019	8.75%	**$ 14,572**	**$ 14,552**	$ 14,572	$ 14,536
2022 Senior Notes	January 23, 2022	8.75%(1)	**17,918**	**17,385**	17,918	17,344
			$ 32,490	**$ 31,937**	$ 32,490	$ 31,880

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

The 2019 and 2022 Senior Notes bear a fixed interest rate of 8.75% with semi-annual interest payments due January 31 and July 31 of each year, and have identical covenants and rights.

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

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 March 31, 2019, the senior notes are presented net of $0.6 million in issue costs which are amortized over the remaining term using a weighted average effective interest rate of 9.6%.

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

On May 7, 2019, Perpetual announced it will early redeem the $14.6 million 2019 Senior Notes due July 23, 2019, effective June 11, 2019. The redemption will be funded by the issuance of $15.7 million 2022 Senior Notes.

Equity

At March 31, 2019 there were 60.0 million common shares outstanding, net of 0.9 million shares held in trust to resource employee compensation programs. During the first quarter of 2019, 0.3 million shares were purchased by the independent trustee to be held in trust, for a total cost to the Company of $0.1 million (Q1 2018 – nil). Basic and diluted weighted average shares outstanding for the three months ended March 31, 2019 were 60.1 million (Q1 2018 – 59.3 million).

At May 7, 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)	**May 7, 2019**
Share options[(1)]	**4.7**
Performance share rights[(2)]	**1.3**
Compensation awards[(3)]	**5.9**
Warrants[(4)]	**6.5**
Total	**18.4**

(1) As at March 31, 2019, 3.8 million outstanding share options have an exercise price that is greater than the closing price of the Company's common shares of $0.36 per share. Excluding these options, the number of potentially issuable common shares would be 0.9 million.

(2) The performance share rights that vest and become redeemable are a multiple of the performance share rights granted, dependent upon the achievement of certain performance metrics over the vesting period. As at March 31, 2019, performance multipliers of 1.0 have been assumed for those unvested awards granted in 2018.

(3) As at March 31, 2019, 2.0 million deferred options have an exercise price that is greater than the closing price of the Company's common shares of $0.36 per share. Excluding these deferred options, the number of potentially issuable common shares pursuant to the compensation awards would be 3.9 million.

(4) As at March 31, 2019, all outstanding warrants have an exercise price of $2.34 per share, which is greater than the closing price of the Company's common shares of $0.36 per share. Excluding these warrants, the number of potentially issuable common shares would be nil.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q1 2019**	Q4 2018[3]	Q3 2018[3]	Q2 2018[3]
Financial				
Oil and natural gas revenue	**22,199**	21,510	20,504	20,774
Net loss	**(4,892)**	(331)	(12,259)	(1,325)
Per share – basic and diluted	**(0.08)**	(0.01)	(0.20)	(0.02)
Cash flow from operating activities	**9,292**	5,163	6,729	8,435
Adjusted funds flow[1]	**6,362**	8,052	5,155	7,847
Per share – basic and diluted	**0.11**	0.13	0.09	0.13
Capital expenditures	**1,238**	5,617	4,343	2,031
Net payments (proceeds) on acquisitions and dispositions	**–**	(1,285)	4,341	(7,012)
Net capital expenditures	**1,238**	4,332	8,684	(4,981)
Common shares (*thousands*)				
Weighted average – basic and diluted	**60,111**	60,448	60,468	59,876
Operating				
Daily average production				
Natural gas (*MMcf/d*)	**50.0**	44.9	46.9	53.1
Oil (*bbl/d*)	**1,121**	1,301	1,022	971
NGL (*bbl/d*)	**785**	715	730	806
Total (*boe/d*)	**10,240**	9,491	9,569	10,620
Average prices				
Realized natural gas price (*$/Mcf*)[2]	**3.54**	4.38	2.83	2.62
Realized oil price (*$/bbl*)[2]	**41.12**	19.83	48.57	53.26
Realized NGL price (*$/bbl*)	**32.16**	35.73	56.02	60.77

($ thousands, except as noted)	Q1 2018[3]	Q4 2017[3]	Q3 2017[3]	Q2 2017[3]
Financial				
Oil and natural gas revenues	23,340	23,810	20,026	19,728
Net loss	(6,465)	(6,498)	(8,082)	(7,219)
Per share – basic and diluted	(0.11)	(0.11)	(0.14)	(0.12)
Cash flow from operating activities	11,198	10,953	5,778	4,728
Adjusted funds flow[1]	9,101	12,541	8,199	5,265
Per share – basic and diluted	0.15	0.21	0.14	0.09
Capital expenditures	14,897	19,047	25,392	4,006
Net payments (proceeds) on acquisitions and dispositions	926	970	680	609
Net capital expenditures	15,823	20,017	26,072	4,615
Common shares (*thousands*)				
Weighted average – basic and diluted	59,345	59,338	59,152	59,045
Operating				
Daily average production				
Natural gas (*MMcf/d*)	65.9	60.8	51.8	45.1
Oil (*bbl/d*)	900	888	978	1,049
NGL (*bbl/d*)	848	738	733	665
Total (*boe/d*)	12,742	11,765	10,330	9,223
Average prices				
Realized natural gas price (*$/Mcf*)[2]	2.65	3.22	3.11	3.18
Realized oil price (*$/bbl*)[2]	48.31	47.30	43.01	43.91
Realized NGL price (*$/bbl*)	57.61	54.17	39.06	44.28

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

The Company's oil and natural gas 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 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 May 7, 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**
April 2019	7,913	1.65	1.37	Financial
May 2019	10,500	1.03	1.09	Physical
April 2019 – October 2019	10,551	1.74	1.08	Physical
June 2019 – October 2019	6,000	1.10	1.01	Financial
June 2019 – October 2019	5,000	1.23	1.01	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for April and May 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 May 7, 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**
April 2019 – October 2019	(5,000)	(1.64)	(1.76)	Physical
April 2019 – December 2019	2,500	(1.55)	(1.65)	Physical
May 2019 – December 2019	7,500	(1.50)	(1.65)	Financial
June 2019	(5,000)	(1.98)	(1.94)	Physical
November 2019 – December 2019	10,000	(1.54)	(1.27)	Physical
January 2020 – December 2020	15,000	(1.41)	(1.49)	Financial
January 2020 – December 2020	12,500	(1.41)	(1.49)	Physical
January 2021 – December 2021	5,000	(1.15)	(1.34)	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for April and May 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 May 7, 2019.

Crude Oil

The Company had entered into financial WTI 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**
April 2019 – December 2019	500	60.00	72.40	61.48	Financial

(1) Market prices for April are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on May 7, 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**
April 2019 – December 2019	750	(25.22)	(16.47)	Financial
May 2019	400	(9.50)	(8.43)	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 April and May 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 May 7, 2019.

The following table provides a summary of WCS fixed price contracts:

Term	Volumes (*bbl/d*)	WCS average price (*$/bbl*)[(1)]	Market prices (*$/bbl*)[(2)]	Type of contract
January 2020 - December 2020	250	50.00	48.20	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices are based on forward WCS prices as of market close on May 7, 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$ thousands/month*)	Strike rate (*US$/Cdn$*)[(1)]	Market prices (*US$/Cdn$*)[(2)]
April 2019 – October 2019	2,000	1.31	1.34
November 2019 – March 2020	2,000	1.29	1.34
April 2020 – October 2020	1,500	1.30	1.34

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for April 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 May 7, 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 having commenced 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	**40,000**

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

ACCOUNTING PRONOUNCEMENTS

Recently adopted

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

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

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

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

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

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

The adoption of the new standard had the following impact on the Company's Q1 2019 financial results, compared to what would have occurred had the new accounting policy not been adopted:

(*$ thousands, except as noted*)	**Impact on net loss**	**Impact on net cash flows from operating activities and adjusted funds flow(1)**
Production and operating expense	23	23
General and administrative expense	84	84
Depletion and depreciation expense	(96)	–
Cash interest on lease liabilities	(50)	(50)
Net IFRS 16 implementation impact	**(39)**	**57**

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

Further information about changes to our accounting policies resulting from the adoption of IFRS 16 can be found in Note 2 to the condensed interim consolidated financial statements.

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.

INTERNAL CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures

There were no changes in the Corporation's internal control over financial reporting during the period beginning on January 1, 2019 and ended March 31, 2019 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

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 ("G&A"), 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.