MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc.'s ("Perpetual", the "Company" or the "Corporation") operating and financial results for the year ended December 31, 2017 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes for the years ended December 31, 2017 and 2016. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are referred to the advisories for additional information regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information and Statements" section of this MD&A. The date of this MD&A is February 22, 2018.

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 netbacks", "cash costs", "gas over bitumen revenue, net of payments", "net working capital deficiency (surplus)", "net debt and net bank debt", "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 operating activities as defined by GAAP, these terms are useful supplemental measures to evaluate operating performance. Users are cautioned however that these measures should not be construed as an alternative to net income (loss) or net cash flows from 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 as a key measure to assess the ability of the Company to generate the funds necessary to finance operating activities and capital expenditures. Adjusted funds flow excludes the change in non-cash working capital and expenditures on decommissioning obligations since Perpetual believes the timing of collection, payment or incurrence of these items involves a high degree of discretion and as such, may not be useful for evaluating Perpetual's operating performance. To make reported adjusted funds flow in this MD&A more comparable to industry practice, the Company reclassifies certain exploration and evaluation costs from operating to investing activities in the adjusted funds flow reconciliation. These exploration and evaluation costs include dry hole costs in addition to geological and geophysical costs, which are expensed in the period incurred. The Company has also reclassified the change in gas over bitumen royalty financing from financing to operating activities in the calculation of adjusted funds flow, in order to present these payments net of gas over bitumen royalty credits. These payments are indexed to gas over bitumen royalty credits and are recorded as a reduction to the Corporation's gas over bitumen royalty financing obligation in accordance with IFRS. Additionally, the Company has excluded payments of restructuring costs associated with the disposition of the Shallow Gas Properties, which management considers to not be related to cash flow from operating activities. Restructuring costs include employee downsizing costs and surplus office lease obligations. Adjusted funds flow per share is calculated using the same weighted average number of shares outstanding used in calculating earnings per share. Adjusted funds flow is not intended to represent net cash flows from (used in) operating activities calculated in accordance with IFRS.

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

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except per share amounts*)	**2017**	2016	**2017**	2016
Net cash flows from (used in) operating activities	**10,953**	4,740	**19,170**	(7,136)
Changes in non-cash working capital	**779**	(2,539)	**9,480**	4,910
Expenditures on decommissioning obligations	**912**	370	**2,336**	3,803
Exploration and evaluation - geological and geophysical costs	**–**	(3)	**(22)**	23
Change in gas over bitumen royalty financing	**(337)**	(726)	**(2,421)**	(2,164)
Payments of restructuring costs	**234**	1,484	**2,550**	1,484
Adjusted funds flow	**12,541**	3,326	**31,093**	920
Adjusted funds flow per share	**0.21**	0.06	**0.54**	0.02

Adjusted funds flow netbacks: Adjusted funds flow netbacks are determined by deducting general and administrative expenses, cash financing costs, gas over bitumen royalty credits net of payments and exploration and evaluation lease rental costs from operating netbacks. Management uses adjusted funds flow netbacks as a key measure to assess its overall profitability per boe, relative to current commodity prices.

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 finance expenses.

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.

Net debt and net bank debt: Net bank debt is measured as current and long-term bank indebtedness 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 TOU share margin loans and the principal amount of Senior Notes reduced for the mark-to-market value of the TOU share investment. Net bank debt and net debt are used by management to analyze borrowing capacity.

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 (described below) share investment, TOU share margin loans and current portion of provisions.

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

Realized revenue: Realized revenue is the sum of realized natural gas revenue, realized oil revenue and realized NGL revenue which includes realized gains (losses) on financial natural gas, crude oil and foreign exchange contracts but excludes any realized gains (losses) resulting from contracts related to the disposition of the Shallow Gas Properties. Realized revenue, excluding foreign exchange contracts 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 and basis differentials. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices, and as such, any related realized gains or losses are considered part of the Corporation's realized price.

Enterprise value: Enterprise value is equal to net debt plus 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.

2017 FINANCIAL RESULTS

The strategic focusing of our asset base, strengthening of our balance sheet and effective execution of our growth-oriented capital program delivered attractive results in 2017.

Our focus in 2017 was enabled by the disposition on October 1, 2016 of 5,900 boe/d of mature, high cost shallow gas assets in east central and northeast Alberta for nominal cash consideration and the transfer of $128.0 million of associated decommissioning obligations to the purchaser (the "Shallow Gas Properties"). At the time of sale, the Shallow Gas Properties represented 42% of total production and 18% of proved plus probable reserves. The disposition was the primary reason for the $3.9 million improvement in adjusted funds flow in the fourth quarter of 2016 compared to the third quarter of 2016 and contributed to improved full year 2017 financial performance relative to 2016.

Our balance sheet was strengthened in early 2017 through the execution of a series of financing transactions. We extended the repayment term of $17.9 million of Senior Notes to 2022 that previously were scheduled to mature in 2018 and 2019. We issued $45 million of second lien term loans due in 2021 and raised gross proceeds of $9.0 million through the private placement of common shares and warrants. We early redeemed $27.1 million of Senior Notes that were scheduled to mature in 2018.

Our strengthened balance sheet provided the foundation to invest in our liquids-rich gas, West Central core area and our heavy oil properties located in eastern Alberta. Exploration and development capital spending in 2017 was $73.0 million, a five-fold increase over 2016, adding proved plus probable reserves equivalent to 248% of 2017 production at a finding and development ("F&D") cost of $6.16/boe (finding development and acquisition ("FD&A") cost of $5.98/boe). Our FD&A recycle ratio (operating netback/FD&A cost) for 2017 was an attractive 2.4 times.

Production for the fourth quarter of 2017 averaged 11,765 boe/d, increasing 45% over the prior year period. Production for the 2017 year was 9,876 boe/d, down 30% from 2016 reflecting the sale of the Shallow Gas Properties. Cash costs comprised of royalties, production and operating, transportation, general and administrative and cash finance expenses decreased by 17% in the fourth quarter of 2017 compared to the prior year period to $11.92/boe, due to diligent cost management and the impact of increased production in 2017 on a substantially fixed cost base. For the year ended December 31, 2017, cash costs were $14.77/boe, down 10% compared to 2016.

Realized revenue per boe was $23.60/boe in the fourth quarter of 2017 and $23.59/boe for the 2017 year, up 29% and 42% over the prior year comparable periods, respectively. Improved oil and natural gas liquids ("NGL") commodity prices combined with improved realized natural gas prices driven by hedging and price optimization strategies, contributed to the increase in realized revenue per boe in 2017.

Cash flow from operating activities in the fourth quarter of 2017 was $11.0 million or $0.18/share, up 131% over the prior year comparable period. Cash flow from operating activities for the year ended December 31, 2017 was $19.2 million or $0.33/share, compared to cash used in operating activities of $7.1 million or $0.14/share in the prior year period.

Adjusted funds flow in the fourth quarter of 2017 was $12.5 million or $0.21/share, up 277% over the prior year comparable period. Adjusted funds flow for the 2017 year was $31.1 million or $0.54/share, compared to $0.9 million or $0.02/share in the prior year period.

2018 OUTLOOK

In response to material commodity market changes, Perpetual has revised its 2018 capital plan to preserve the value of its East Edson reserves by deferring any additional 2018 development drilling at East Edson in West Central Alberta and accelerating spending on highly economic heavy oil projects at Mannville in eastern Alberta, for a net reduction to the 2018 capital budget to $23 - $27 million. On November 10, 2017, the Company announced that the Board of Directors approved a capital spending program of $37 million for 2018, close to 75% concentrated in East Edson, developing natural gas reserves with liquids in the Wilrich formation, and 25% in eastern Alberta, primarily targeting heavy oil development at Mannville. The forward average AECO and WTI prices for Calendar 2018 as of November 9, 2017 were $2.01 per GJ (US$3.09 per MMBtu NYMEX) and US$56.91 per bbl, respectively. The revised capital plan accounts for the wind down of gas focused drilling activities at East Edson and results in a modified capital plan with investment split more evenly between the two core operating areas and natural gas and oil commodities.

Although NYMEX natural gas prices have remained relatively steady as natural gas storage has been depleted through the winter to below historical levels driven by strong demand, the basis differential to Western Canadian markets has widened and AECO forward natural gas prices have weakened materially over the same period. Perpetual's five-year market diversification contracts that came into effect on November 1, 2017 have substantially mitigated the impact on adjusted funds flow of lower AECO prices, as the contracts appreciate in value with wider differentials to each of the five market price points. However, Perpetual measures economic returns for all new natural gas investments against current unhedged AECO strip pricing, as incremental volumes, net of royalties, would be effectively sold to this market. At the same time, the forward market for West Texas Intermediate oil has strengthened, translating into slightly stronger expected prices for Perpetual's blend of heavy oil, condensate and natural gas liquids ("NGL").

Perpetual's two core areas of operation provide a diversified portfolio of investment opportunities. The Company will remain flexible to reallocate spending between natural gas focused projects at East Edson and heavy oil projects depending on where the most profitable economics can be secured. For the first quarter, the one outstanding frac of the third extended reach horizontal ("ERH") well at East Edson will be postponed until late in the third quarter of 2018. Perpetual will re-direct spending to its heavy oil development project of the Birch General Petroleum A pool in Mannville, including a four well multi-lateral horizontal drilling program along with water handling and disposal facilities, previously budgeted for the second half of 2018. Assuming continued weakness in AECO natural gas prices, the four-well East Edson drilling program previously planned for the third quarter of 2018 will be deferred pending stronger AECO natural gas prices. Three (2.3 net) development wells at Mannville are expected to proceed as planned in the third quarter, along with three to six (3.0 to 6.0 net) additional wells at Mannville to evaluate the future horizontal development potential of three undeveloped heavy oil pools.

The table below summarizes planned capital spending and drilling activities for the first and second half of 2018.

Exploration and Development Forecast Capital Expenditures

	H1 2018 $ millions	# of wells (gross/net)	H2 2018 $ millions	# of wells (gross/net)	Total 2018 $ millions	# of wells (gross/net)
West Central	8	1/1.0	3	0/0.0	11	1/1.0
Eastern	6	4/4.0	6 - 10	6 - 9/5.3 – 8.3	12 - 16	10 - 13/9.3 – 12.3
Total(1)(2)	**14**	**5/5.0**	**9 - 13**	**6-9/5.3 – 8.3**	**23 - 27**	**11 - 14/10.3 – 13.3**

(1) Excludes expected decommissioning expenditures of $2.0 to $2.5 million in 2018.
(2) Previous capital spending forecast released November 10, 2017 included forecast total exploration and development capital spending of $37 million. Please see news release dated November 10, 2017 for details.

Production Guidance

With the accelerated availability of increased firm transportation on TCPL, coupled with the capital re-allocation strategy to heavy oil, first quarter 2018 production is expected to average close to 13,300 boe/d, approximately 1,100 boe/d higher than previously forecast. Natural declines at East Edson will decrease natural gas and NGL production during the second and third quarters when AECO gas prices are expected to be at their lowest levels for the year. Then production will ramp up again with the planned late third quarter frac of the ERH well waiting on completion. Based on total exploration and development capital spending in 2018 of $23 to $27 million, Perpetual forecasts production to average approximately 11,500 boe/d for 2018 and forecasts to exit the year at approximately 10,700 boe/d (17% oil and NGL) as gas production at East Edson declines and Mannville heavy oil production ramps up driven by increased drilling and waterflood activity. While the growth in average daily production will be diminished from the original budget plan of 32%, year-over-year growth is still expected to be 17%, with a higher proportion of oil and NGL than previously forecast.

Marketing and Hedging Update

Concurrent with the 2016 sale of the Shallow Gas Properties, Perpetual entered into commodity price contracts whereby Perpetual was obligated to provide an AECO floor price of $2.58/GJ on 33,611 GJ/d through August 31, 2018. Perpetual's obligation has now been fixed at a cost of $8.5 million in 2018.

During the third quarter of 2017, Perpetual diversified its natural gas price exposure from AECO by entering into arrangements to effectively shift the sales point of 34.1 MMcf/d to a basket of five North American natural gas hub pricing points for a five-year period commencing November 1, 2017, increasing to 39.0 MMcf/d commencing April 1, 2018. Based on current futures prices, these market diversification contracts will provide a significant premium over AECO prices in 2018 and provide significant diversification to Perpetual's natural gas pricing point exposure (net of royalties) as detailed below:

Market/Pricing Point

Natural gas	Estimated Proportion of 2018 Production
AECO[1]	0%
AECO fixed price	27%
Empress	5%
Dawn	11%
Michcon	7%
Chicago	18%
Malin	16%
Total natural gas	84%
Natural gas liquids - Condensate[1]	3%
Natural gas liquids - Other[1]	2%
Crude oil - Fixed	3%
Crude oil - Floating[1]	8%
Total	100%

(1) Net of royalties.

Adjusted Funds Flow and Sensitivities

The following revised 2018 guidance assumptions, based on settled and forward 2018 market prices as at January 25, 2018 and operations assumptions as outlined above, have been used:

- Exploration and development capital spending of $23 to $27 million;
- 2018 average daily production of 11,500 boe/d (17% oil and NGL);
- Calendar 2018 average NYMEX gas price of US$2.98 per MMBtu;
- Calendar 2018 average West Texas Intermediate ("WTI") oil price of US$63.54 per bbl;
- Calendar 2018 average Western Canadian Select ("WCS") differential of (US$23.83) per bbl;
- Calendar 2018 average NYMEX to AECO basis differential of (US$1.77) per MMBtu;
- Calendar 2018 average CAD/US$1.00 exchange rate of 1.235; and
- 2018 cash costs, including royalties, of $13.00 to $14.00 per boe, increased slightly from previous outlook due to the impact of lower forecast production volumes on a mainly fixed cost structure.

Based on the capital spending plan and production assumptions outlined above, and the current forward market for oil and natural gas prices at market pricing points, Perpetual forecasts 2018 adjusted funds flow of $33 to $37 million ($0.56/share to $0.62/share) down from $35 to $40 million previously forecast in its news release dated November 10, 2017 due to lower forecast production and natural gas pricing.

Over the past year, natural gas prices at AECO have become disconnected from the North American market as resource development in the Western Canadian Sedimentary Basin has outpaced market access and market demand. Perpetual's market diversification contracts were put in place to mitigate the risk of lower AECO pricing due to widening of the basis differentials relative to various other markets and enable price participation in NYMEX-based markets. Incorporating the assumptions outlined above, and presuming NYMEX and AECO basis differentials remain constant to each of the diversified natural gas pricing points, Perpetual's estimated adjusted funds flow sensitivity to various commodity prices is as follows:

Projected 2018 Adjusted Funds Flow Sensitivities [1][2]

		Calendar 2018 NYMEX price (***$US/MMBtu***)						
	($CAD millions)	**$2.25**	**$2.50**	**$2.75**	**$3.00**	**$3.25**	**$3.50**	**$3.75**
Calendar 2018 WTI price (*$US/bbl*)	**$45.00**	20.7	22.8	24.8	26.9	29.0	31.1	33.2
	$50.00	22.5	24.5	26.6	28.7	30.8	32.9	35.0
	$55.00	25.3	27.4	29.5	31.6	33.7	35.8	37.8
	$60.00	28.0	30.1	32.2	34.2	36.3	38.4	40.5
	$65.00	29.8	31.9	33.9	36.0	38.1	40.2	42.3
	$70.00	31.6	33.7	35.7	37.8	39.9	42.0	44.1
	$75.00	33.4	35.4	37.5	39.6	41.7	43.8	45.9

(1) Sensitivities assume non-AECO market price points adjust commensurately and the Calendar 2018 AECO basis and WCS differentials are fixed at (US$1.77)/MMBtu and (US$23.83)/bbl respectively.

(2) The current settled and forward average NYMEX, WTI, NYMEX to AECO basis differential and WCS prices for Calendar 2018 as at February 6, 2018, were US$2.88/MMBtu, US$61.25/bbl, (US$1.73)/MMBtu, (US$25.60)/bbl respectively. The CAD/US$1.00 exchange rate for Calendar 2018 as at February 6, 2018 was 1.249.

The following additional sensitivities can be applied to estimate additional changes to projected 2018 adjusted funds flow:

- For every $0.25 USD/MMBtu widening or increase (narrowing or decrease) in the Calendar 2018 NYMEX to AECO basis differential, adjusted funds flow increases (decreases) by $4.4 million;
- For every $5.00 USD/bbl widening or increase (narrowing or decrease) in the Calendar 2018 WCS differential, adjusted funds flow decreases (increases) by $1.6 million; and
- For every $0.01 increase (decrease) in the Calendar 2018 CAD/US$1.00 exchange rate, adjusted funds flow increases (decreases) by $0.9 million.

At the current forward market for natural gas and oil prices, 2018 adjusted funds flow is expected to exceed capital spending and other obligations. Year end 2018 net debt, net of the current market value of the Company's investment in shares of Tourmaline Oil Corp. ("TOU" – TSX) of close to $35 million, is forecast at $105 to $110 million, with a corresponding estimated net debt to trailing twelve months adjusted funds flow ratio of approximately 3.2 times. The year end 2018 net debt forecast is based on net debt at December 31, 2017 of $106.0 million, plus 2018 capital spending of $23 to $27 million, 2018 decommissioning expenditures of $2.0 to $2.5 million, funding of Shallow Gas Property marketing obligation of $8.5 million, less 2018 adjusted funds flow of $33 to $37 million.

2017 CAPITAL EXPENDITURES

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2017**	2016	**2017**	2016
Exploration and development	**19,028**	7,044	**72,956**	14,039
Other	**19**	25	**79**	541
Capital expenditures	**19,047**	7,069	**73,035**	14,580
Geological and geophysical costs[1]	**–**	(3)	**(22)**	23
Acquisitions	**–**	–	**432**	12
Net payments (proceeds) on dispositions	**970**	1,785	**1,990**	(5,984)
Total	**20,017**	8,851	**75,435**	8,631

(1) Geological and geophysical costs and dry hole costs are expensed directly in the Corporation's consolidated statement of income (loss); they are considered by Perpetual to be more closely related to investing activities than operating activities, and therefore are included with capital expenditures for the purposes of this MD&A.

In the fourth quarter of 2017, three (3.0 net) East Edson wells were drilled, with two having been completed in the first quarter of 2018. Additional compression was added at the 100% owned and operated West Wolf Lake 10-3 plant, to align compression and process capacity at the facility, bringing the plant capacity to 65 MMcf/d, and area capacity to 78 MMcf/d including the 15% working interest capacity held at a third-party operated facility in Rosevear. This expansion was completed in December 2017 for $2.1 million, on budget and three months ahead of schedule to accommodate the accelerated availability of increased firm transportation on TCPL to 78 MMcf/d from April 1, 2018 to December 17, 2017.

Exploration and development spending by area

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2017**	2016	**2017**	2016
West Central	**17,789**	3,897	**65,130**	10,538
Eastern	**1,239**	3,147	**7,826**	3,501
Total	**19,028**	7,044	**72,956**	14,039

Perpetual's exploration and development spending in 2017 totaled $73.0 million, a five-fold increase over $14.0 million in 2016. Compared to Perpetual's capital spending outlook provided with its third quarter 2017 MD&A, spending was at the low end of the range as the drilling of one well at East Edson was deferred until the first quarter of 2018. Approximately 90% of Perpetual's exploration and development spending during the fourth quarter and year ended December 31, 2017 was focused on liquids-rich natural gas development activities in West Central Alberta.

Spending on West Central liquids-rich gas projects for 2017 included $65.1 million for the drilling of 14 (13.4 net) natural gas wells, with 13 (13.0 net) in the Company's East Edson area. Drilling and completion operations continued into the first quarter of 2018 at East Edson, with one (1.0 net) additional liquids-rich gas well drilled and two (2.0 net) wells completed since year end.

A total of $7.8 million was spent in the Mannville area during 2017, drilling one (1.0 net) exploratory natural gas well and four (3.3 net) oil wells. The remaining activity was primarily directed towards waterflood optimization with the conversion of one new injector, one new disposal well and pipeline construction for water management. Perpetual plans to drill and complete up to four horizontal multi-leg oil wells and install additional waterflood infrastructure at Mannville in the first quarter of 2018. Low variable operating costs and synergy with well abandonment programs in the Mannville area result in gas recompletions paying out within 6-12 months even at low commodity prices. These will continue during 2018 with up to 20 recompletions planned.

Dispositions

Net payments on dispositions were $1.0 million in the fourth quarter of 2017 and $2.0 million for the year ended December 31, 2017, and included $1.0 million and $2.9 million of net payments, respectively, associated with the retained marketing arrangements related to the Shallow Gas Property disposition in 2016. As part of the disposition of the Shallow Gas Properties, Perpetual provided the purchaser with AECO floor price protection at $2.58/GJ and retained price participation to the extent AECO prices exceed $2.81/GJ on 33,611 GJ/d from October 1, 2016 through to August 31, 2018. Net payments of $2.9 million were made in 2017 (2016 - $0.5 million) with respect to these retained marketing arrangements. As at December 31, 2017, the fair value of the remaining AECO floor price obligation recorded on Perpetual's balance sheet was $7.7 million. With the weakening of AECO forward prices early in 2018, the floor price obligation increased and has been extinguished at a cost of $8.5 million to be paid over the remaining marketing arrangement term, ending August of 2018. Net proceeds on dispositions, principally of undeveloped land and seismic data in the fourth quarter of 2017 was nil (Q4 2016 – payments of $1.2 million) and $0.9 million for the year ended December 31, 2017 (2016 - $6.5 million).

Expenditures on decommissioning obligations

For the fourth quarter of 2017 and the 2017 year, expenditures on decommissioning obligations were $0.9 million and $2.3 million, respectively. Decommissioning expenditures were focused primarily in the Mannville area. Six reclamation certificates were received in the fourth quarter of 2017 (2017 year – 35) from the Alberta Energy Regulator which will reduce mineral and surface lease rental payments and municipal property taxes going forward. Decommissioning expenditures declined in 2017 from $3.8 million in 2016, primarily as a result of the disposition of the Shallow Gas Properties. Expenditures of $2.0 million to $2.5 million are anticipated in 2018.

SUMMARY OF QUARTERLY AND ANNUAL NET INCOME (LOSS)

Three months ended December 31,

	2017		2016	
	($ thousands)	***($/boe)***	*($ thousands)*	*($/boe)*
Realized revenue[1]	**25,541**	**23.60**	13,696	18.34
Royalties[2]	**(2,651)**	**(2.45)**	(3,070)	(4.11)
Production and operating expenses	**(3,738)**	**(3.45)**	(1,604)	(2.15)
Transportation costs	**(1,479)**	**(1.37)**	(969)	(1.30)
Operating netback[1]	**17,673**	**16.33**	8,053	10.78
Unrealized gains (losses) on derivatives	**(1,729)**	**(1.60)**	5,639	7.55
Gas over bitumen royalty credit and other	**399**	**0.37**	696	0.93
Exploration and evaluation	**(156)**	**(0.14)**	417	0.56
General and administrative expense	**(2,850)**	**(2.63)**	(3,655)	(4.89)
Share-based payments, non-cash	**(887)**	**(0.82)**	(1,480)	(1.98)
Depletion and depreciation	**(9,415)**	**(8.70)**	(6,948)	(9.30)
Gain (loss) on dispositions	**(3,949)**	**(3.65)**	19,515	26.13
Restructuring costs	**–**	**–**	(4,720)	(6.32)
Impairment reversals	**–**	**–**	6,900	9.24
Finance expense	**(1,265)**	**(1.17)**	(4,722)	(6.32)
Change in fair value of TOU share investment	**(4,319)**	**(3.99)**	684	0.92
Net income (loss)	**(6,498)**	**(6.00)**	20,379	27.30
Net income (loss) per share - basic	**(0.11)**		0.39	

(1) See "Non-GAAP measures" in this MD&A.
(2) Includes $1.4 million in gross overriding royalty payments at East Edson for the three months ended December 31, 2017 (Q4 2016- $1.9 million).

Years ended December 31,

	2017		2016	
	($ thousands)	***($/boe)***	*($ thousands)*	*($/boe)*
Realized revenue[1]	**85,027**	**23.59**	86,104	16.65
Royalties[2]	**(11,973)**	**(3.32)**	(9,415)	(1.82)
Production and operating expenses	**(16,299)**	**(4.52)**	(35,019)	(6.77)
Transportation costs	**(5,051)**	**(1.40)**	(7,925)	(1.53)
Operating netback[1]	**51,704**	**14.35**	33,745	6.53
Unrealized gains on derivatives	**2,550**	**0.71**	13,340	2.58
Gas over bitumen royalty credit and other	**2,460**	**0.68**	1,984	0.38
Exploration and evaluation	**(3,283)**	**(0.91)**	(3,790)	(0.73)
General and administrative expense	**(11,943)**	**(3.31)**	(17,153)	(3.32)
Share-based payments, non-cash	**(4,310)**	**(1.20)**	(5,911)	(1.14)
Depletion and depreciation	**(33,436)**	**(9.28)**	(54,317)	(10.50)
Gain (loss) on dispositions	**(9,450)**	**(2.62)**	21,605	4.18
Restructuring costs	**–**	**–**	(5,638)	(1.09)
Impairment reversals	**–**	**–**	6,900	1.33
Finance expense[3]	**(7,592)**	**(2.11)**	(24,847)	(4.81)
Change in fair value of TOU share investment	**(22,671)**	**(6.29)**	58,897	11.39
Gain on Security Swap	**–**	**–**	81,310	15.72
Net income and dividends from gas storage investment	**–**	**–**	1,024	0.20
Net income (loss)	**(35,971)**	**(9.98)**	107,149	20.72
Net income (loss) per share - basic	**(0.62)**		2.11	

(1) See "Non-GAAP measures" in this MD&A.
(2) Includes $6.7 million in gross overriding royalty payments at East Edson for the year ended December 31, 2017 (2016 - $5.5 million).
(3) 2016 includes $0.3 million in cash transaction costs in relation to the Security Swap.

Net income (loss)

For the fourth quarter ended December 31, 2017, Perpetual recorded a net loss of $6.5 million ($0.11/share) compared to net income of $20.4 million ($0.39/share) in the prior year period. Net loss in the fourth quarter of 2017 included a loss on disposition of $3.9 million (Q4 2016 –$19.5 million gain) associated with the Shallow Gas Properties and an unrealized loss of $4.3 million on its TOU share investment (Q4 2016 - $0.7 million gain). Also included in the Q4 2016 net income was a net impairment reversal of $6.9 million. Excluding these items, the Company recorded net income in the fourth quarter of $1.7 million compared to a net loss of $6.7 million in the prior year period. Improved performance was due to higher realized commodity prices, cost reductions, increased production and lower depletion rates.

For the year ended December 31, 2017, Perpetual recorded a net loss of $36.0 million ($0.62/share) compared to net income of $107.1 million ($2.11/share) for 2016. The $143.1 million year-over-year decrease in net income was primarily due to the absence of the 2016 $81.3 million gain on exchange of Senior Notes for TOU share investment and resulting reduction in interest expense, the $81.6 million year-over-year decrease in the change in fair value of TOU share investment (2017 - $22.7 million loss, 2016 - $58.9 million gain) and the $36.5 million year-over-year decrease in gains on disposition (2017 - $8.8 million loss, 2016 – $27.8 million gain) principally due to the Shallow Gas Property disposition. Income (loss) from operating activities in 2017, before impairment losses (reversals), restructuring expense and loss (gain) on dispositions was $3.7 million compared to ($32.1 million), representing a $35.8 million improvement due to higher realized commodity prices and cost reductions in 2017, and the sale of the Shallow Gas Properties in 2016.

Cash flow from operating activities

For the fourth quarter ended December 31, 2017, cash flow from operating activities was $11.0 million, up 134% from $4.7 million in the prior year period, primarily due to higher realized commodity prices, cost reductions and a 45% increase in average daily production.

For the year ended December 31, 2017, cash flow from operating activities was $19.2 million, compared to negative $7.1 million in 2016. Year-over-year improvements in commodity prices combined with significant cost reductions in 2017 more than offset the impact of the 30% decline in average daily production from 2016 to 2017. Through the Company's diligent focus on controlling costs along with the impact of the Shallow Gas Property disposition, Perpetual has seen expense reductions in all areas compared to 2016. These reductions were partially offset by higher royalties caused by improving commodity prices.

Adjusted funds flow

For the fourth quarter ended December 31, 2017, adjusted funds flow was $12.5 million, a $9.2 million increase over the prior year period due to the 45% increase in production, higher realized commodity prices and lower costs compared to the prior year period.

For the year ended December 31, 2017, adjusted funds flow was $31.1 million compared to $0.9 million in 2016, consistent with outlook guidance provided with the Company's third quarter 2017 MD&A of $28 to $32 million. Improved performance was driven by higher realized commodity prices combined with significant cost reductions, partially offset by the 30% decline in average daily production in 2017 compared to 2016.

Netbacks

The following tables highlight Perpetual's operating and adjusted funds flow netbacks per boe for the three months and years ended December 31, 2017 and 2016:

	Three months ended December 31, 2017			Three months ended December 31, 2016		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**9,894**	**1,871**	**11,765**	6,444	1,674	8,118
Total petroleum and natural gas revenue	**20.28**	**31.08**	**22.00**	22.20	31.03	24.02
Realized gains on derivatives	**–**	**–**	**1.60**	–	–	(5.68)
Royalties	**(2.26)**	**(3.44)**	**(2.45)**	(4.44)	(2.84)	(4.11)
Production and operating expenses	**(1.72)**	**(12.63)**	**(3.45)**	(2.18)	(2.03)	(2.15)
Transportation costs	**(1.23)**	**(2.10)**	**(1.37)**	(0.93)	(2.70)	(1.30)
Total operating netback	**15.07**	**12.91**	**16.33**	14.65	23.46	10.78
Gas over bitumen, net of payments and other			**0.06**			(0.04)
Exploration and evaluation – lease rentals			**(0.14)**			0.57
General and administrative expense			**(2.63)**			(4.89)
Finance expense, cash			**(2.02)**			(1.96)
Adjusted funds flow netback			**11.60**			4.46

($/boe)	Year ended December 31, 2017 West Central	Eastern	Total	Year ended December 31, 2016 West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**7,896**	**1,980**	**9,876**	7,453	6,675	14,128
Total petroleum and natural gas revenue	**20.84**	**29.98**	**22.67**	15.91	15.56	15.74
Realized gains on derivatives	**–**	**–**	**0.92**	–	–	0.91
Royalties	**(3.27)**	**(3.53)**	**(3.32)**	(2.63)	(0.91)	(1.82)
Production and operating expenses	**(2.68)**	**(11.88)**	**(4.52)**	(2.93)	(11.06)	(6.77)
Transportation costs	**(1.18)**	**(2.27)**	**(1.40)**	(0.94)	(2.19)	(1.53)
Total operating netback	**13.71**	**12.30**	**14.35**	9.41	1.40	6.53
Gas over bitumen, net of payments and other			**0.02**			(0.03)
Exploration and evaluation – lease rentals			**(0.20)**			(0.20)
General and administrative expense			**(3.31)**			(3.32)
Finance expense, cash			**(2.22)**			(2.89)
Dividends from gas storage facility investment			**–**			0.10
Adjusted funds flow netback			**8.64**			0.19

For the fourth quarter ended December 31, 2017, operating netback of $16.33/boe ($17.7 million) increased 51% from $10.78/boe ($8.1 million) in the prior year period due to increased realized revenue per boe and lower royalties, despite significantly lower AECO natural gas index prices. Royalties per boe decreased in the fourth quarter of 2017 due to lower AECO natural gas index prices. Production and operating expenses per boe were higher in the fourth quarter of 2017 due to the absence of $1.8 million ($2.41/boe) of non-recurring credits recorded in the prior year period associated with the Shallow Gas Properties that were sold.

For the year ended December 31, 2017, Perpetual's operating netback of $14.35/boe ($51.7 million) increased 120% from $6.53/boe ($33.7 million) in 2016. This improvement was due primarily to the 42% ($6.94/boe) increase in realized revenue per boe, combined with a 33% ($2.25/boe) decrease in operating costs and 9% ($0.13/boe) decrease in transportation costs, which more than offset the 82% increase in royalties caused by higher reference prices than in 2016.

Perpetual's adjusted funds flow netback was $11.60/boe for the fourth quarter of 2017, up 160% over the prior year period due to improved operating netback performance and lower general and administrative costs due to staff and office space reductions implemented following the sale of the Shallow Gas Properties, combined with increasing production during 2017.

For the year ended December 31, 2017, Perpetual's adjusted funds flow netback was $8.64/boe compared to $0.19/boe in 2016, due to improved operating netback performance.

Production

	Three months ended December 31, **2017**	2016	Years ended December 31, **2017**	2016
Natural gas (*MMcf/d*)				
Eastern	**6.0**	4.5	**6.3**	33.8
West Central	**54.8**	35.8	**43.3**	40.9
Total natural gas[(1)]	**60.8**	40.3	**49.6**	74.7
Crude oil (*bbl/d*)				
Eastern[(2)]	**869**	917	**929**	1,041
West Central	**19**	19	**19**	17
Total crude oil	**888**	936	**948**	1,058
Total NGL (*bbl/d*)[(3)]	**738**	467	**655**	614
Total production (*boe/d*)	**11,765**	8,118	**9,876**	14,128

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

Fourth quarter production averaged 11,765 boe/d, up 3,647 boe/d or 45% from the prior year period production of 8,118 boe/d, due primarily to strong growth in West Central production driven by the 2017 drilling program. Total natural gas, oil and NGL production for the year ended December 31, 2017 of 9,876 boe/d was 30% lower than 2016 (14,128 boe/d), primarily reflecting the disposition of the Shallow Gas Properties on October 1, 2016, offset partially by the growth in West Central production throughout the year.

Natural gas production at West Central during the three months ended December 31, 2017 increased by 53% from the prior year period, contributing most of the Corporation's natural gas production growth in the fourth quarter of 2017. This growth reflects the ramp up from East Edson drilling, with ten (10.0 net) wells coming on stream during the first nine months. Perpetual's 2017 annual natural gas production of 49.6 MMcf/d decreased 34% from 2016 (74.7 MMcf/d), reflecting the sale of approximately 35.5 MMcf/d of eastern Alberta production related to the Shallow Gas Properties effective October 1, 2016.

During the second half of 2017, industry transportation maintenance activities restricted available capacity and temporarily depressed natural gas prices at AECO. In response, Perpetual voluntarily shut-in an average 500 boe/d of production at East Edson in the fourth quarter (2017 year – 245 boe/d) to take advantage of temporary situations where natural gas could be purchased at nominal cost and delivered against pre-sold volumes.

Consistent with increased capital spending and growing East Edson natural gas production, NGL production of 738 bbl/d in the three months ended December 2017 increased 58% from the same period in 2016 (467 bbl/d). Condensate production represented 62% of fourth quarter and 2017 full year NGL production (Q4 2016 - 69%; 2016 – 66%). On a full year basis, the increased production of East Edson liquids-rich natural gas resulted in a 7% increase in NGL production in 2017 (655 bbl/d) compared to 2016 (614 bbl/d).

Crude oil production in eastern Alberta was 5% lower in the fourth quarter of 2017 compared to the same period in 2016, as minimal capital was allocated to the area in the third and fourth quarters of 2017. The Company continues to see positive response from waterflood activities in several pools, mitigating production declines by restoring pressure support. Oil production of 948 bbl/d for 2017 was 10% lower than 2016 (1,058 bbl/d) mainly due to natural declines and minimal capital spending on crude oil drilling and waterflood activities after the first quarter of 2017.

Commodity Prices

	Three months ended December 31,		Years ended December 31,	
	2017	2016	**2017**	2016
Reference prices				
AECO Daily Index (*$/GJ*)	**1.60**	2.93	**2.04**	2.05
AECO Daily Index (*$/Mcf*)(1)	**1.69**	3.09	**2.16**	2.16
Alberta Gas Reference Price (*$/GJ*)(2)	**1.62**	2.48	**2.02**	1.81
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**55.40**	49.29	**50.95**	43.32
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(12.26)**	(14.32)	**(11.98)**	(13.84)
WCS average (*$CAD/bbl*)(3)	**54.79**	46.51	**50.66**	39.20
Average Perpetual prices				
Natural gas (*$/Mcf*)(1)				
AECO Daily Index	**1.69**	3.09	**2.16**	2.16
Heat Content Premium	**0.17**	0.32	**0.21**	0.15
Market Diversification Contracts	**0.19**	–	**0.06**	–
Realized gains (losses) on financial and physical gas derivatives	**0.71**	(0.74)	**0.80**	0.30
Realized gains (losses) on prompt month price optimization	**0.46**	(0.26)	**0.28**	(0.19)
Realized natural gas price (*$/Mcf*)(4)	**3.22**	2.41	**3.51**	2.42
Percent of AECO Daily Index	**191**	78	**163**	112
Premium to AECO Daily Index due to higher heat content	**10%**	10%	**10%**	7%
Realized oil price (*$/bbl*)(4)	**47.30**	38.95	**41.62**	37.60
Realized natural gas liquids ("NGL") price (*$/bbl*)	**54.17**	46.99	**46.60**	35.45

(1) Converted from $/GJ using a standard conversion rate of 1.06 GJ:1 Mcf.
(2) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.
(3) Derived internally using the Bank of Canada average foreign exchange rate of US$1.00 = $1.27 for the three months ended December 31, 2017 (Q4 2016 – 1.33) and 1.30 for the year ended December 31, 2017 (2016 – 1.33).
(4) Realized natural gas and oil prices includes physical forward sales contracts for which delivery was made during the reporting period and realized gains and losses on financial derivatives. Realized gains and losses from foreign exchange contracts are excluded.

Reduced North American production in the first half of 2017, as well as increased demand from LNG exports from the US Gulf of Mexico and pipeline exports to Mexico allowed the US supply demand balance to loosen causing NYMEX natural gas prices to increase 26% from US$2.46/MMBtu in 2016 to an average of US$3.11/MMBtu in 2017. In comparison, the AECO Monthly Index prices only increased 16% from $1.98/GJ in 2016 to $2.30/GJ in 2017. During 2017, AECO became disconnected from the North American market as production growth in the Western Canadian Sedimentary Basin has outpaced market access and market demand. The increase of WTI to US$50.95/bbl in 2017 from US$43.32/bbl in 2016 was related to the gradual reduction in global oil inventories during 2017 as a result of increased global demand of crude by 1.6 MMbbl/d over 2016 levels and the supply restrictions implemented by OPEC effective January 1, 2017 to the extent of 1.2 MMbbl/d along with an additional cut from select non-OPEC producers of up to 0.6 MMbbl/d.

Revenue

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2017**	2016	**2017**	2016
Petroleum and natural gas revenue				
Natural gas(1)	**16,009**	12,272	**54,444**	59,902
Oil(1)	**4,122**	3,647	**16,139**	13,529
NGL	**3,679**	2,021	**11,139**	7,972
Total petroleum and natural gas revenue	**23,810**	17,940	**81,722**	81,403
Realized gains on derivatives(2)	**1,731**	(4,244)	**3,305**	4,701
Realized revenue	**25,541**	13,696	**85,027**	86,104
Unrealized gains (losses) on derivatives	**(1,729)**	5,639	**2,550**	13,340
Total revenue	**23,812**	19,335	**87,577**	99,444
Realized revenue *($/boe)*	**23.60**	18.34	**23.59**	16.65
Total revenue *($/boe)*	**22.00**	25.89	**24.29**	19.23

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

Realized revenue was $25.5 million in the fourth quarter of 2017, up 86% from the prior year period due to a 45% increase in production combined with a 29% increase in average realized prices. Included in realized revenues in the fourth quarter of 2017, were $1.7 million in realized gains on derivatives comprised of $2.0 million of gains on natural gas hedges, partially offset by $0.3 million of losses on WTI and WCS differential hedges.

For the 2017 year, realized revenue was $85.0 million, down 1% from the prior year as a 30% decrease in production was offset by a similar increase in average realized prices. Included in realized revenues for the 2017 year, were $3.3 million in realized gains on derivatives comprised of $9.2 million of gains on natural gas hedges, partially offset by $1.7 million of losses from oil hedges and $4.2 million of losses on foreign exchange hedges.

Natural gas realized revenue in the fourth quarter of 2017 was $18.0 million, comprising 70% of total realized revenue while natural gas represented 86% of production on a boe/d basis. Compared to the prior year period, natural gas realized revenue increased by 102% in the fourth quarter of 2017, due to a 34% increase in realized natural gas prices and a 51% increase in production due to the ramp up of East Edson production during 2017. Realized natural gas prices in the fourth quarter of 2017 were $3.22/Mcf representing 191% of the AECO Daily Index price compared to 78% in the prior year period. Realized gains on financial and physical gas derivatives added $0.71/Mcf to the realized price in the fourth quarter (2016 – $0.74/Mcf loss). Realized gains on prompt month price optimization operations added $0.46/Mcf in the fourth quarter (2016 - $0.26/Mcf loss) and included $0.09/Mcf ($0.5 million) associated with the purchase of third party gas at nominal cost to deliver against pre-sold volume commitments. Effective November 1, 2017, Perpetual commenced sales to the five-year term, NYMEX based contract on 35.0 MMcf/d which contributed a $0.19/Mcf ($1.0 million incremental revenue) increase in Perpetual's average realized natural gas price compared to the AECO Daily Index in the fourth quarter. This contract increases to 40.0 MMcf/d effective April 1, 2018. On a pro forma basis, had the full 40.0 MMcf/d contract been in place for the entire fourth quarter, Perpetual's realized natural gas price would have increased by an additional $0.15/Mcf ($0.8 million additional revenue).

Oil realized revenue in the fourth quarter of 2017 was $3.9 million, comprising 15% of total realized revenue and 8% of production on a boe/d basis. Compared to the prior year, oil realized revenue increased by 15%, due to a 21% increase in price partially offset by a 5% reduction in production. Perpetual's realized oil price in the fourth quarter of 2017 of $47.30/bbl reflected increased WTI pricing combined with a reduced WCS differential compared to the prior year period. Included in Perpetual's average oil price are deductions for quality adjustments, loss allowance, terminal fees and diluent blending fees.

NGL revenue in the fourth quarter of 2017 was $3.7 million, comprising 14% of total realized revenue and 6% of production on a boe/d basis. Compared to the prior year period, NGL revenue increased by 82% in the fourth quarter of 2017 due to a 15% increase in price and a 58% increase in production associated with the ramp up in production at East Edson during 2017.

Unrealized losses on derivatives of $1.7 million were recorded in the fourth quarter of 2017. Unrealized gains and losses represent the change in mark-to-market value of derivative contracts as forward commodity prices and foreign exchange rates change. Unrealized gains and losses on derivatives are excluded from the Corporation's calculation of cash flow from operating activities as they are non-cash. Derivative gains and losses vary depending on the nature and extent of derivative contracts in place, which in turn, vary with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

Royalties

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2017**	2016	**2017**	2016
Crown	**260**	515	**2,066**	1,676
Freehold and overriding[(1)]	**2,391**	2,555	**9,907**	7,739
Total	**2,651**	3,070	**11,973**	9,415
Crown (*% of P&NG revenue*)	**1.1**	2.9	**2.5**	2.1
Freehold and overriding (*% of P&NG revenue*)	**10.0**	14.2	**12.1**	9.5
Total (*% of P&NG revenue*)	**11.1**	17.1	**14.6**	11.6
$/boe	**2.45**	4.11	**3.32**	1.82

(1) Includes $1.4 million in gross overriding royalty payments at East Edson ("East Edson GORR") for the three months ended December 31, 2017 (Q4 2016 – $1.9 million) and $6.7 million for the year ended December 31, 2017 (2016 - $5.5 million).

Royalty expense for the fourth quarter of 2017 was $2.7 million, representing 11.1% of total petroleum and natural gas revenue, down from $3.1 million and 17.1% respectively, in the prior year period. Lower royalty rates reflect the decrease in the Alberta Gas Reference Price and the AECO daily index price compared to the prior year period which are used to determine crown royalty and freehold and overriding royalty expense. 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 production increases, the fixed nature of the gross overriding royalty results in a decreased expense on a percentage of revenue and unit of production basis, which also contributed to the reduced overriding royalty rate in the fourth quarter of 2017 compared to the prior period.

On an annual basis, royalty expenses for 2017 were $12.0 million, representing a 27% increase in the effective combined average royalty rate on P&NG revenue to 14.6% from 11.6% in 2016. Average crown royalty rates increased to 2.5% in 2017 compared to 2.1% in 2016, due primarily to higher Alberta natural gas reference prices and increasing oil prices.

Production and operating expenses

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2017**	2016	**2017**	2016
Production and operating expenses	**3,738**	1,604	**16,299**	35,019
$/boe	**3.45**	2.15	**4.52**	6.77

Production and operating expenses increased 133% to $3.7 million in the fourth quarter of 2017 compared to $1.6 million recorded during the same period in 2016. The fourth quarter of 2016 operating expenses include $1.8 million ($2.41/boe) of non-recurring adjustment credits associated with the sold Shallow Gas Properties. After adjusting for these non-recurring items, production and operating expenses decreased by 24% on a boe basis compared to the prior year period due to lower maintenance and repair costs, purchased energy costs, and processing fees combined with increased production from the low-cost East Edson property in West Central.

For the full year, production and operating expenses decreased 53% to $16.3 million in 2017 compared to $35.0 million in 2016. This decrease reflected company-wide cost saving initiatives, operating efficiencies at the low-cost Company owned and operated gas plant at East Edson, and the full year impact in 2017 of the sale of the high cost Shallow Gas Properties.

Transportation costs

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2017**	2016	**2017**	2016
Transportation costs	**1,479**	969	**5,051**	7,925
$/boe	**1.37**	1.30	**1.40**	1.53

Transportation costs include clean oil trucking and NGL transportation as well as costs to transport natural gas from the plant gate to commercial sales points. For the fourth quarter of 2017, transportation costs were $1.5 million, an increase of 52% over the prior year period, consistent with production volume increases. For the 2017 year, transportation costs decreased to $5.1 million from $7.9 million in 2016, reflecting lower oil and gas sales volumes combined with a higher percentage of gas production from West Central properties in 2017, where transportation costs averaged $1.18/boe compared to $2.27/boe for eastern Alberta.

The increase in firm transportation capacity on TCPL to 78 MMcf/d in late December 2017 is expected to increase 2018 transportation costs by approximately $1.0 million over 2017 levels.

Gas over bitumen

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2017**	2016	**2017**	2016
Gas over bitumen revenue	**151**	696	**2,116**	1,984
Payments on gas over bitumen royalty financing[1]	**(337)**	(726)	**(2,421)**	(2,164)
Gas over bitumen, net of payments	**(186)**	(30)	**(305)**	(180)
$/boe	**(0.17)**	(0.04)	**(0.08)**	(0.03)

(1) At December 31, 2017, the fair value of the gas over bitumen royalty financing is estimated to be $2.7 million (2016 - $8.3 million).

Perpetual records revenue in relation to gas over bitumen royalty credits received under the Natural Gas Royalty Regulation as a result of its working interests in a number of natural gas wells which have been shut-in pursuant to shut-in orders issued by the Government of Alberta. During 2017, Perpetual recorded $2.1 million in gas over bitumen revenue; an increase of 7% ($0.1 million) from the same period in 2016 attributable to the 12% increase in Alberta Gas Reference Prices, partially offset by the annual 10% decline in deemed production.

Gas over bitumen royalty credits earned throughout 2017 were offset by payments of $2.4 million (2016 – $2.2 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 credit received in the period due to timing differences. The monthly payment commitment expires concurrent with the gas over bitumen 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 as revenue in accordance with Perpetual's accounting policies with the monthly payments recognized separately 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 2017, the gas over bitumen royalty financing obligation was reduced by $5.6 million, comprised of payments of $2.4 million (2016 - $2.2 million) in addition to an unrealized gain of $3.2 million (2016 - loss of $0.5 million). The gain has been included in non-cash finance expense and represents a decrease in the fair value of the gas over bitumen royalty financing obligation compared to 2016, as a result of lower forecasted natural gas reference prices.

Exploration and evaluation ("E&E")

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2017**	2016	**2017**	2016
Lease rentals	**156**	(424)	**703**	1,040
Geological and geophysical costs[1]	**–**	(3)	**(22)**	23
Lease expiries	**–**	10	**2,602**	2,727
Total E&E expense	**156**	(417)	**3,283**	3,790

(1) Geological and geophysical expenditures and dry hole costs are expensed directly in the Corporation's statement of income (loss); they are considered by Perpetual to be more closely related to investing activities than operating activities, and therefore are included with capital expenditures for the purposes of this MD&A.

Total E&E expense includes lease rentals on undeveloped acreage, geological and geophysical costs and the write down of carrying costs related to lease expiries. E&E costs of $3.3 million in 2017 were 13% lower than 2016 due to decreased lease rental costs, geological and geophysical costs and fewer lease expiries. The reduction in lease rental costs was largely due to dispositions in 2016 along with decisions in 2016 and 2017 to let several leases expire, primarily in eastern Alberta.

General and administrative ("G&A") expenses

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2017**	2016	**2017**	2016
Cash G&A expense	**3,707**	4,465	**15,377**	21,190
Overhead recoveries	**(857)**	(810)	**(3,434)**	(4,037)
Total G&A expense	**2,850**	3,655	**11,943**	17,153
Total G&A expense *($/boe)*	**2.63**	4.89	**3.31**	3.32

Total G&A expense in the fourth quarter of 2017 was $2.9 million and $11.9 million for the full year 2017, down 22% and 30% respectively, from prior period levels. Lower expenses resulted from staff and office space reductions in the fourth quarter of 2016 following the Shallow Gas Property disposition combined with diligent expense management. On a per boe basis, total G&A expense was $2.63/boe in the fourth quarter of 2017 and $3.31/boe for the 2017 year, down 46% and 1% respectively compared to the prior year periods driven by cost reductions combined with increasing production during 2017.

Share-based payments

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2017**	2016	**2017**	2016
Share-based payments expense (non-cash)	**887**	1,480	**4,310**	5,911
Share-based payments expense (non-cash) *($/boe)*	**0.82**	1.98	**1.20**	1.14

Non-cash share-based payments expense for the year ended December 31, 2017 decreased $1.6 million compared to the same period in 2016. This decrease was the result of reductions in staffing levels following the Shallow Gas Property disposition in the fourth quarter of 2016.

Restructuring costs

(*$ thousands, except as noted*)	**2017**	2016
Employee downsizing costs	**–**	2,926
Onerous office lease contract	**–**	2,712
Total restructuring costs	**–**	5,638
Restructuring costs *($/boe)*	**–**	1.09

During 2016, the Company recognized onerous lease obligations totaling $2.7 million in relation to corporate office space which was no longer being utilized as a result of a terminated sublease and staff reductions related to the disposition of the Shallow Gas Properties. The unused office space was recorded as an onerous contract as the unavoidable costs associated with the lease contract exceeded the economic benefits to be received. Also included in restructuring costs was $2.9 million in relation to employee downsizing costs of which $1.3 million was paid in 2016 with the remainder paid out in 2017.

Depletion and depreciation

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2017**	2016	**2017**	2016
Depletion and depreciation	**9,415**	6,948	**33,436**	54,317
$/boe	**8.70**	9.30	**9.28**	10.50

Perpetual recorded $33.4 million of depletion and depreciation expense for the year ended December 31, 2017, down 38% from $54.3 million in 2016. On a per boe basis, 2017 depletion and depreciation expense of $9.28/boe was 12% lower than the prior year, due primarily to the lower depletion rates associated with the Company's East Edson assets, which make up a larger percentage of Perpetual's production on which depletion expense is recorded. The Company's 2017 capital program added proved plus probable reserves at FD&A costs of $5.98/boe which also contributed to lower depletion rates in 2017 compared to the prior year.

Impairment

For the year ended December 31, 2017, the Company assessed impairment indicators for the Company's Cash Generating Units ("CGUs"). There was no impairment or impairment reversal recognized in 2017.

For the year ended December 31, 2016, the Company assessed impairment indicators for the Company's CGUs. In performing the review, management determined that the disposition of the Shallow Gas Properties justified calculation of the recoverable amount of the Northern CGU. In addition, technical revisions to Mannville heavy oil reserves related to improved recovery methods along with realized lower operating costs and capital efficiencies justified a review for impairment reversals for the Eastern CGU. The Company determined the recoverable amount of Northern and Eastern CGUs using VIU based on the net present value of cash flows from oil, natural gas, and NGL reserves using estimates of total proved plus probable reserves evaluated or reviewed by the Company's independent reserves evaluators along with the associated year-end commodity price forecast, and an estimate of market discount rates between 12 and 20 percent to consider risks specific to the asset.

At December 31, 2016, the Company recorded a net impairment reversal of $6.9 million to net income which was comprised of the following:

- The Company determined that the carrying amount of the Northern CGU of $6.7 million exceeded the recoverable amounts. Accordingly, an impairment charge of $5.8 million was included in net income reducing the carrying amount to $0.9 million; and

- The Company determined that the recoverable amount of the Eastern CGU exceeded its carrying amount of $33.1 million by $15.9 million; accordingly, a reversal of $12.7 million was recognized in net income representing the full reversal of previously recorded impairments adjusted for depletion resulting in a carrying amount $45.8 million.

Finance expenses

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2017**	2016	**2017**	2016
Cash interest				
Interest on revolving bank debt	**314**	129	**1,078**	2,749
Interest on TOU share margin loans	**227**	–	**687**	–
Interest on Term Loan	**892**	–	**2,441**	–
Interest on Senior Notes	**755**	1,325	**3,798**	11,942
Total cash interest	**2,188**	1,454	**8,004**	14,691
Total cash interest *($/boe)*	**2.02**	1.95	**2.22**	2.84
Non-cash finance expense				
Amortization of debt issue costs	**198**	56	**620**	509
Accretion on decommissioning obligations	**204**	178	**775**	2,643
Change in fair value of gas over bitumen royalty financing	**(1,325)**	1,079	**(3,184)**	497
Change in fair value of TOU share margin loans	**–**	1,943	**1,377**	6,507
Non-cash finance expense (recovery)	**(923)**	3,256	**(412)**	10,156
Finance expenses recognized in net income (loss)	**1,265**	4,710	**7,592**	24,847

Total cash interest expense was $2.2 million in the fourth quarter of 2017, an increase of $0.7 million from the comparable prior year period primarily due to a 25% increase in year-over-year debt levels. Total cash interest expense for the 2017 year was $8.0 million, down $6.7 million from 2016 due to the cancellation during the second quarter of 2016 of $214.4 million principal amount 8.75% Senior Notes in exchange for 4.4 million TOU shares owned by Perpetual (the "Security Swap"), partially offset by higher year-over-year debt levels in 2017.

Non-cash finance expense was a recovery of $0.9 million in the fourth quarter of 2017 compared to an expense of $3.3 million in the prior year period. A reduction in the fair value of the gas over bitumen royalty obligation due to lower AECO future gas prices at December 31, 2017 contributed to $2.4 million of the variance with the remaining difference due to the absence of the change in the fair value of the TOU share put option margin loans of $1.9 million recorded in the fourth quarter of 2016 as these loans were refinanced in the third quarter of 2017 without embedded put option derivatives. For the 2017 year, non-cash finance expense was a recovery of $0.4 million compared to an expense of $10.2 million in 2016 due to the same factors that impacted the fourth quarter variance as well as a $1.9 million reduction in accretion on decommissioning obligations due to the $128.0 million reduction in decommissioning obligations that resulted from the disposition of the Shallow Gas Properties in 2016.

Gain on exchange of Senior Notes for TOU share investment

During the second quarter of 2016, the Company recorded a net gain of $81.3 million from the Security Swap transaction, whereby $114.0 million of outstanding 2018 Senior Notes and $100.4 million of outstanding 2019 Senior Notes were repurchased and cancelled through the exchange of 4.4 million TOU shares and cash payments of $3.9 million for accrued interest. The fair market value of TOU shares exchanged was $130.5 million based on an average closing price of $29.64 per share. Included in the Security Swap were $81.6 million 2018 Senior Notes and $57.0 million 2019 Senior Notes held by directors and officers of the Company or entities controlled by them.

Change in fair value of TOU share investment

During 2017, the Company recorded an unrealized loss of $22.7 million related to the change in fair value of TOU share investment, which represents the change in value of TOU shares held from December 31, 2016 ($35.91 per share) to December 31, 2017 ($22.78 per share). At December 31, 2017, Perpetual owned 1.67 million TOU shares (December 31, 2016 – 1.85 million shares) having a fair market value of $38.0 million (December 31, 2016 – $66.3 million)

Gas storage facility investment

During the second quarter of 2016, the Corporation disposed of its interest in a gas storage facility investment for net cash proceeds of $19.7 million, resulting in a net loss on disposition of $6.2 million. Prior to the disposition of the gas storage facility investment, Perpetual recorded income of $1.0 million and received dividends of $0.5 million, representing the Corporation's share of total dividends declared prior to the closing of the sale transaction. In 2017, a $0.7 million negative adjustment was recorded in connection with the disposition of the gas storage facility.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Perpetual's strategy includes maintaining a strong capital base to retain investor, creditor and market confidence to support the execution of its business plans. The Company manages its capital structure and adjusts its capital spending in light of changes in economic conditions 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 loans and net working capital, with value and liquidity enhanced through the current ownership of TOU shares. In order 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.

During the year ended December 31, 2017, the Company completed several financing transactions to strengthen Perpetual's liquidity and debt repayment profile and secure funding for the Company's 2017 capital expenditure program. The significant financing transactions are as follows:

- Exchange of $17.4 million aggregate principal amount of its existing Senior Notes maturing in 2018 and 2019 for new 8.75% Senior Notes having an extended maturity date of January 23, 2022 (the "2022 Senior Notes"). The remaining $27.6 million Senior Notes maturing in 2018 were redeemed by cash repayment of $27.1 million and $0.5 million through an exchange for new 2022 Senior Notes;
- Establishment of the term loan with total availability of $45 million bearing annual interest at 8.1% and maturing March 14, 2021 (the "Term Loan"). In addition, for no additional consideration, 5.4 million warrants were issued and valued at $0.8 million which entitle the lender to acquire common shares on a one for one basis for a period of up to three years, at an exercise price of $2.34 per share (the "Warrants"). The initial draw on the Term Loan was $35 million with the second and final draw of $10 million occurring on October 5, 2017;
- Issuance of 5.1 million common shares and 1.1 million additional Warrants for aggregate gross proceeds of $9 million on March 14, 2017;
- Three borrowing base increases to the Company's reserve based, revolving bank debt (the "Credit Facility") comprised of a $14 million increase in March of 2017, a $20 million increase in July 2017 and a $25 million increase in November 2017 to a total borrowing limit of $65 million. Restricted cash of $2 million was released by the lender. The Credit Facility maturity date was extended to May 31, 2019; and
- Establishment of a new $18.7 million TOU share margin loan secured by 1.67 million TOU shares maturing in July 2018. Proceeds from the new margin loan along with borrowings under the Credit Facility were used to repay the $36.5 million TOU share put option margin loans that were scheduled to mature in August and November of 2017. Proceeds of $1.0 million were realized from the sale of underlying TOU share put options.

Capital Management

(*$ thousands, except as noted*)	**December 31, 2017**	December 31, 2016
Revolving bank debt	**31,581**	–
Term Loan, measured at principal amount	**45,000**	–
TOU share margin loans, measured at principal amount	**18,490**	39,953
Senior Notes, measured at principal amount	**32,490**	60,573
TOU share investment(1)	**(37,985)**	(66,343)
Net working capital deficiency(2)	**16,404**	3,917
Net debt(2)	**105,980**	38,100
Shares outstanding at end of period (*thousands*) (3)	**59,263**	53,421
Market price at end of period (*$/share*) (3)	**1.10**	2.35
Market value of shares	**65,189**	125,539
Enterprise value(2)	**171,169**	163,639
Net debt as a percentage of enterprise value	**62**	23
Trailing twelve months adjusted funds flow(2)	**31,093**	920
Net debt to trailing twelve months adjusted funds flow	**3.4**	41.4

(1) The TOU share investment is based on the December 31, 2017 closing price per the Toronto Stock Exchange ($22.78 per share) and 1.67 million TOU shares held (December 31, 2016 – 1.85 million TOU shares held with a closing price of $35.91 per share).
(2) See "Non-GAAP measures" in this MD&A.
(3) Shares outstanding are presented net of shares held in trust.

At December 31, 2017, Perpetual had total net debt of $106.0 million, up $67.9 million (178%) from December 31, 2016. The increase reflects the increase in capital investment during the year combined with a $28.4 million reduction in the fair value of TOU shares.

As at December 31, 2017, Perpetual had available liquidity (defined as the Credit Facility Borrowing Limit plus TOU share investment, less borrowing and letters of credit issued under the Credit Facility and TOU share margin loan) of $49 million. As at December 31, 2017, 59% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow improved significantly during 2017 to 3.4 times at December 31, 2017.

Perpetual maintains credit ratings with Moody's and Standard & Poors ("S&P") that facilitate access to the high yield bond market to refinance existing debt or raise additional funding if required. On July 7, 2017, Moody's Investors Service announced that it had upgraded Perpetual's corporate credit rating from Caa2 – Negative Outlook to Caa1 – Stable Outlook. On November 20, 2017, S&P upgraded Perpetual's credit rating by two rating notches from CCC- to CCC+ with a stable outlook, based on Perpetual's improved liquidity.

TOU share margin loans

At December 31, 2017, Perpetual had an $18.4 million TOU share margin loan secured by 1.67 million TOU shares that matures on July 31, 2018 representing a 40% loan to TOU share value lending ratio at the date of funding. Interest rates are indexed to the same applicable Banker's Acceptance margins as the Credit Facility, ranging between 1.5% and 4.0%. 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 loan compared to the daily 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 loan to restore the lending ratio to 40%. As at December 31, 2017, the Lending Ratio was 48% of the closing market value of the pledged TOU shares. Subsequent to December 31, 2017, the TOU share price has declined in value, prompting the Company to voluntarily pay down the TOU share margin loan by $2.5 million to maintain the Lending Ratio at less than 55%, funded from borrowings on its Credit Facility. The TOU share margin loan is designated as a financial liability measured at amortized cost.

Proceeds from this margin loan along with borrowings under its Credit Facility were used to repay the TOU share put option margin loans during the third quarter of 2017. Proceeds of $1.0 million were realized from the sale of underlying TOU share put options.

Prior to repayment, the TOU share put option margin loans were hybrid financial instruments comprising a debt host with an embedded TOU share put option derivative related to indexation of the future settlement amount to changes in the market price of TOU shares pledged as collateral. The Company had designated the TOU share put option margin loans as financial liabilities which were measured at fair value through profit and loss. For the year ended December 31, 2017, an unrealized loss of $1.4 million (2016 - $6.5 million unrealized loss) is included in finance expense, representing the change in fair value of the TOU share put options during the year.

In addition to the Lending Ratio requirements, the TOU share margin loan is subject to customary non-financial covenants. The Company was in compliance with all TOU share margin loan covenants at December 31, 2017.

Revolving Bank Debt

As at December 31, 2017, the Company's reserve-based Credit Facility had a borrowing limit (the "Borrowing Limit") of $65.0 million (December 31, 2016 - $6.0 million) under which $31.6 million was drawn (December 31, 2016 – nil) and $3.9 million of letters of credit had been issued (December 31, 2016 - $4.0 million). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 2.0% and 4.5% depending on the Company's ratio of net debt to adjusted funds flow.

The Credit Facility will continue to revolve until May 31, 2018 and may be extended for a further 364-day period subject to approval by the syndicate. If not extended, the Credit Facility will cease to revolve and all outstanding advances will be repayable on May 31, 2019. The next Borrowing Limit redetermination is scheduled on or prior to May 31, 2018.

Borrowings are secured by general security agreements covering all of the Company's assets with the exception of TOU shares that have been pledged as security for the TOU share margin loans and certain lands pledged to the gas over bitumen royalty financing counterparty.

The effective interest rate on the Credit Facility at December 31, 2017 was 4.3%. For the years ended December 31, 2017 and 2016, if interest rates changed by 1% with all other variables held constant, the annual impact on interest expense and net income (loss) would be $0.3 million (2016 – $0.1 million).

Prior to the July 4, 2017 Borrowing Limit redetermination, the Credit Facility was subject to a working capital covenant which required the Company to maintain net working capital plus outstanding letters of credit not exceeding the Borrowing Limit. Net working capital includes the sum of cash and cash equivalents, restricted cash, accounts receivable, prepaid expenses and unpledged TOU shares less accounts payable and accrued liabilities and accrued interest on Senior Notes and the Term Loan up to the Credit Facility maturity date. On July 4, 2017, as part of the Borrowing Limit redetermination, Perpetual's lenders removed this working capital covenant. The Credit Facility also contains provisions which restrict the Company's ability to pay dividends on or repurchase its common shares.

At December 31, 2017, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term Loan

On March 14, 2017, Perpetual entered into the Term Loan which included the issuance of 5.4 million Warrants to purchase common shares.

	December 31, 2017
Balance, beginning of period	$ –
Principal amount of Term Loan issued	**45,000**
Value allocated to Warrants issued	**(769)**
Issue costs	**(1,361)**
Amortization of issue costs	**363**
Balance, end of year	**$ 43,233**

The Term Loan matures on March 14, 2021 and bears interest at 8.1% per annum with semi-annual interest payments due June 30 and December 31 of each year. The $45 million Term Loan consisted of an initial draw of $35 million completed upon closing with the final $10 million drawn on October 5, 2017. Amounts borrowed under the Term Loan that are repaid are not available for re-borrowing. The Company may not repay the Term Loan prior to the second anniversary thereof, except with payment of a make whole premium.

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

At December 31, 2017, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior Notes

			December 31, 2017		December 31, 2016	
	Maturity date	Interest rate	Principal	Carrying Amount	Principal	Carrying amount
2018 Senior Notes	March 15, 2018	8.75%	$ –	$ –	$ 36,013	$ 35,847
2019 Senior Notes	July 23, 2019	8.75%	14,572	14,476	24,560	24,273
2022 Senior Notes	January 23, 2022	8.75%(1)	17,918	17,204	–	–
			$ 32,490	$ 31,680	$ 60,573	$ 60,120

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

On January 23, 2017, the Company exchanged $8.4 million and $9.0 million aggregate principal amount of 2018 Senior Notes and 2019 Senior Notes respectively for $17.4 million new 8.75% Senior Notes with a maturity date of January 23, 2022 (collectively, the "Senior Notes"). Included in the exchange were $3.7 million 2018 Senior Notes and $4.3 million 2019 Senior Notes held by directors and officers of the Company or entities controlled by them. The 2022 Senior Notes bear a fixed rate of 9.75% for the first year of issuance and 8.75% thereafter, and have identical covenants and rights as the existing 2018 and 2019 Senior Notes.

On April 17, 2017, Perpetual redeemed $27.1 million aggregate outstanding principal amount of its 8.75% Senior Notes maturing March 15, 2018 for cash and exchanged the remaining $0.5 million for the issuance of an equal amount of 2022 Senior Notes. In mid-July, $1.0 million face value of 2019 Senior Notes were purchased at 96.75% of face value and retired.

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% 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% of the Senior Notes at a premium to face value. Within one year of maturity, the Company may redeem up to 100% 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, Term Loan, TOU share margin loans 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% of TTM EBITDA from January 1, 2011 to the end of the most recently completed fiscal quarter plus 100% 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% of the fair market value of any equity contributions made to the Company.

At December 31, 2017 the Senior Notes are presented net of $0.8 million in issue costs which are amortized over the remaining term to maturity using a weighted average effective interest rate of 9.6%.

At December 31, 2017, in addition to the restricted payment covenants noted above, the Senior Notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Equity

Authorized capital consists of an unlimited number of common shares. On March 24, 2016, shareholders of the Company approved the consolidation of common shares on the basis of 20 common shares to one common share, which has been retroactively applied throughout this MD&A.

On March 14, 2017, the Company completed a private placement of 5.1 million equity units for gross proceeds of $9.0 million, of which $8.9 million has been allocated to share capital and $0.1 million to Warrants. Each equity unit consisted of 1 common share and 0.21 Warrants. Included in the issuance were 1.6 million common shares and 0.4 million Warrants issued to directors and officers of the Company or entities controlled by them, for proceeds of $2.9 million. In addition, 5.4 million Warrants valued at $0.8 million were issued in connection with the Term Loan. Each Warrant entitles the holder to acquire common shares on a one for one basis at an exercise price of $2.34 per share (the "Exercise Price") prior to March 14, 2020. If the volume weighted average price of Perpetual's common shares is greater than the Exercise Price for 60 consecutive calendar days, Perpetual has the option to require Warrant holders to exercise all or any portion of the Warrants at any time thereafter.

On November 17, 2016, the Company issued 0.5 million flow-through shares at a price of $2.15 per share for total gross cash proceeds of $1.1 million. The implied premium received in excess of the fair value of the common shares on the date of issue was $0.2 million or $0.44 per share and has been recorded in accounts payable and accrued liabilities pending the incurrence of qualified exploration expenditures by the Company. As at December 31, 2016 the Company was committed to spend $1.1 million on qualified exploration expenditures by December 31, 2017. The exploration expenditures have been incurred in 2017 and renounced to investors.

On January 18, 2016, Perpetual issued 33.3 million common shares of the Company upon closing of a fully backstopped rights offering to issue common shares of Perpetual for gross proceeds of $25 million. Included were 21.4 million common shares issued to entities controlled by the Chairman of Perpetual's Board of Directors for proceeds of $16.1 million.

As at December 31, 2017 and the date of this MD&A, there were 59.3 million common shares outstanding which is net of 0.4 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)	**February 22, 2018**
Share options	**4.0**
Restricted rights	–
Performance share rights[1]	**1.1**
Compensation awards	**4.1**
Warrants	**6.5**
Total	**15.7**

(1) 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 December 31, 2017, performance multipliers of 2.0 and 1.0 have been assumed for those unvested awards granted in 2016 and 2017 respectively.

CONTRACTUAL OBLIGATIONS AND COMMITMENTS

As at December 31, 2017, the Company's contractual obligations over the next five years and thereafter are as follows:

Contractual repayments of financial liabilities *($ thousands)*	**2018**	**2019**	**2020**	**2021**	**2022 and Thereafter**	**Total**
Accounts payable and accrued liabilities	31,410	–	–	–	–	**31,410**
Fair value of derivatives	7,885	–	–	–	–	**7,885**
TOU share margin loans - principal	18,490	–	–	–	–	**18,490**
Revolving bank debt - principal	–	31,826	–	–	–	**31,826**
Term Loan – principal	–	–	–	45,000	–	**45,000**
Senior Notes – principal	–	14,572	–	–	17,918	**32,490**
Gas over bitumen royalty financing	1,152	939	391	257	–	**2,739**
Pipeline transportation commitments	4,193	3,730	2,343	1,022	1,022	**12,310**
Office and other operating lease commitments	1,371	1,065	1,098	1,159	3,815	**8,508**
Total	64,501	52,132	3,832	47,438	22,755	**190,658**

Commodity price risk management

Perpetual's commodity price risk management strategy is focused on managing downside risk and increasing certainty in cash flow from operating activities 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 rate forward contracts and physical or financial swaps 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.

Natural Gas

The following tables provide a summary of derivative natural gas contracts outstanding at February 22, 2018.

The Company has in place open physical and financial natural gas arrangements 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 2018 – October 2018	10,000	2.06	1.16	Financial
April 2018 – March 2019	10,000	1.41	1.43	Financial
September 2018 – March 2019	5,000	1.40	1.68	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices are based on forward AECO Monthly Index prices as of market close on February 22, 2018.

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

Term	**Volumes sold (bought) (MMBTU/d)**	**AECO-NYMEX differential (US$/MMBTU)**	**Market prices (US$/MMBTU)**[(1)]	**Type of contract**
April 2018 – October 2018	7,500	(1.80)	(1.77)	Financial
January 2019 – December 2019	20,000	(1.52)	(1.48)	Financial
January 2020 – December 2020	10,000	(1.41)	(1.36)	Financial

(1) Market prices are based on forward AECO-NYMEX differential prices as of market close on February 22, 2018.

Crude Oil

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

Term	Volumes (*bbl/d*)	Floor price (*US$/bbl*)	Ceiling price (*US$/bbl*)	Market prices (*US$/bbl*)(1)	Type of contract
February 2018 – December 2018	250	50.00	58.40	60.72	Financial
February 2018 – December 2018	250	50.00	60.00	60.72	Financial

(1) Market prices are based on forward WTI oil prices as of market close on February 22, 2018.

Term	Volumes at WTI (*bbl/d*)	Average price (*US$*/bbl)	Market prices (*US$*/bbl)(1)	Type of contract
February 2018 – December 2018	250	63.74	60.72	Fixed Price

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

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 2018 – June 2018	500	(14.45)	(24.55)	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 are based on forward WTI-WCS differential prices as of market close on February 22, 2018.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except where noted)	**Q4 2017**	Q3 2017	Q2 2017	Q1 2017
Financial				
Oil and natural gas revenue	**23,810**	20,026	19,728	18,158
Net loss	**(6,498)**	(8,082)	(7,219)	(14,172)
Per share – basic	**(0.11)**	(0.14)	(0.12)	(0.26)
Per share – diluted	**(0.11)**	(0.14)	(0.12)	(0.26)
Cash flow from (used in) operating activities	**10,953**	5,778	4,728	(2,289)
Adjusted funds flow[1]	**12,541**	8,199	5,243	5,110
Per share – basic	**0.21**	0.14	0.09	0.09
Net capital expenditures				
Capital expenditures	**19,047**	25,392	4,006	24,590
Geological and geophysical costs	**–**	–	(22)	–
Net payments on acquisitions and dispositions	**970**	680	609	163
Net capital expenditures	**20,017**	26,072	4,593	24,753
Common shares (*thousands*)				
Weighted average – basic	**59,338**	59,152	59,045	54,468
Weighted average – diluted	**59,338**	59,152	59,045	54,468
Operating				
Daily average production				
Natural gas (*MMcf/d*)	**60.8**	51.8	45.1	40.7
Oil (*bbl/d*)	**888**	978	1,049	877
NGL (*bbl/d*)	**738**	733	665	479
Total (*boe/d*)	**11,765**	10,330	9,223	8,143
Average prices				
Realized natural gas price (*$/Mcf*)[2]	**3.22**	3.11	3.18	5.04
Realized oil price (*$/bbl*)[2]	**47.30**	43.01	43.91	31.39
NGL price (*$/bbl*)	**54.17**	39.06	44.28	49.70

(1) See "Non-GAAP measures" in this MD&A.
(2) Realized natural gas and oil prices include physical forward sales contracts for which delivery was made during the reporting period and realized gains and losses on financial derivatives. Realized gains and losses from foreign exchange contracts are excluded.

($ thousands, except where noted)	Q4 2016	Q3 2016	Q2 2016	Q1 2016
Financial				
Oil and natural gas revenue	17,940	22,268	16,501	24,694
Net income (loss)	20,379	(10,919)	64,925	32,764
Per share – basic	0.39	(0.21)	1.25	0.72
Per share – diluted	0.37	(0.21)	1.23	0.70
Cash flow from (used in) operating activities	4,740	(1,710)	(3,396)	(6,770)
Adjusted funds flow[1]	3,326	(602)	(1,852)	48
Per share – basic	0.06	(0.01)	(0.04)	0.00
Net capital expenditures				
Capital expenditures	7,069	1,411	1,286	4,814
Geological and geophysical costs	(3)	–	11	15
Net payments (proceeds) on acquisitions and dispositions	1,785	(988)	(302)	(6,466)
Net capital expenditures	8,851	423	995	(1,637)
Common shares (*thousands*)[2]				
Weighted average – basic	52,924	52,253	52,140	45,573
Weighted average – diluted	54,678	52,253	52,904	47,022
Operating				
Daily average production				
Natural gas (*MMcf/d*)	40.3	75.5	85.2	98.2
Oil (*bbl/d*)	936	1,052	1,073	1,174
NGL (*bbl/d*)	467	476	682	836
Total (*boe/d*)	8,118	14,123	15,959	18,378
Average prices				
Realized natural gas price (*$/Mcf*)[3]	2.41	2.12	1.85	3.15
Realized oil price (*$/bbl*)[3]	38.95	38.90	39.17	33.90
NGL price (*$/bbl*)	46.99	35.80	34.71	29.33

(1) See "Non-GAAP measures" in this MD&A.
(2) Common shares and per share amounts have been retroactively adjusted to reflect the consolidation of outstanding common shares on the basis of 20 common shares to one common share on March 24, 2016. All common shares are presented net of shares held in trust.
(3) Realized natural gas and oil prices include physical forward sales contracts for which delivery was made during the reporting period and realized gains and losses on financial derivatives. Realized gains and losses from foreign exchange contracts are excluded.

The Company's oil and natural gas revenues, net income (loss), cash flow from (used in) operating activities and adjusted funds flow are influenced by commodity prices and production levels. Production levels declined through 2016 as net capital expenditures were reduced in response to low commodity prices. In the fourth quarter of 2016, production decreased due to the disposition of approximately 5,900 boe/d of production associated with the Shallow Gas Properties. Capital expenditures increased significantly in 2017, resulting in increasing production, revenues and adjusted funds flow as the year progressed. Capital expenditures are typically low during the second quarter when break-up conditions reduce access for field activities.

SELECTED ANNUAL INFORMATION

($ thousands, except where noted)	**2017**	2016	2015
Financial			
Oil and natural gas revenue	**81,722**	81,403	142,437
Net income (loss)	**(35,971)**	107,149	(89,274)
Per share - basic[1]	**(0.62)**	2.11	(11.89)
Per share – diluted[1]	**(0.62)**	1.98	(11.89)
Cash flow from (used in) operating activities	**19,170**	(7,136)	12,406
Adjusted funds flow	**31,093**	920	2,004
Per share[1][2]	**0.54**	0.02	0.26
Total assets	**365,570**	361,405	603,450
Total long-term liabilities	**144,186**	97,215	443,648
Revolving bank debt	**31,581**	–	
Senior Notes, at principal amount	**32,490**	60,573	275,000
Term Loan, at principal amount	**45,000**	–	–
TOU share margin loans, at principal amount	**18,490**	39,953	60,059
Carrying amount of TOU share investment	**(37,985)**	(66,343)	(145,275)
Net working capital deficiency	**16,404**	3,917	13,832
Total net debt	**105,980**	38,100	203,616
Net capital expenditures			
Capital expenditures	**73,035**	14,580	76,341
Geological and geophysical costs	**(22)**	23	1,526
Net payments (proceeds) on acquisitions and dispositions	**2,422**	(5,972)	(23,710)
Net capital expenditures	**75,435**	8,631	54,157
Common shares (*thousands*)[3]			
End of period[4]	**59,263**	53,421	19,067
Weighted average - basic	**58,017**	50,733	7,507
Weighted average - diluted	**58,017**	54,038	7,507
Operating			
Daily average production			
Natural gas (*MMcf/d*)	**49.6**	74.7	104.2
Oil (*bbl/d*)	**948**	1,058	1,626
NGL (*bbl/d*)	**655**	614	711
Total average production (*boe/d*)	**9,876**	14,128	19,706
Average prices			
Realized natural gas price (*$/Mcf*)	**3.51**	2.42	3.01
Realized oil price (*$/bbl*)	**41.62**	37.60	52.48
NGL price (*$/bbl*)	**46.60**	35.45	33.72
Wells drilled			
Natural gas – gross (net)	**15 (14.4)**	4 (4.0)	6 (4.5)
Crude oil – gross (net)	**4 (3.3)**	– (–)	– (–)
Total – gross (net)	**19 (17.7)**	4 (4.0)	6 (4.5)

(1) Based on weighted average common shares outstanding for the year.
(2) See "non-GAAP measure" in this MD&A.
(3) Common shares and per share amounts have been retroactively adjusted to reflect the consolidation of outstanding common shares on the basis of 20 common shares to one common share on March 24, 2016. Common shares are presented net of shares held in trust.
(4) Reduced by shares held in trust (2017 – 447; 2016 – 260; and 2015 – 47). See "Note 15 to the Audited Consolidated Financial Statements".

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

FUTURE ACCOUNTING PRONOUNCEMENTS

The International Accounting Standards Board (IASB) and the IFRS Interpretations Committee regularly issue new and revised accounting pronouncements which have future effective dates and therefore are not reflected in Perpetual's financial statements. Once adopted these new and amended pronouncements may have an impact on Perpetual's consolidated financial statements. Perpetual's analysis of recent accounting pronouncements is included in the notes to the consolidated financial statements at December 31, 2017 (note 3n).

CORPORATE GOVERNANCE

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

RISK FACTORS

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

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

Perpetual manages these risks by:

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

A complete discussion of risk factors is included in the Corporation's 2017 Annual Information Form ("AIF") available on the Corporation's website at www.perpetualenergyinc.com or on SEDAR at www.sedar.com.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Disclosure controls and procedures

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

Perpetual's CEO and CFO have concluded, based on their evaluation at December 31, 2017, the DC&P are effective to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

Management's annual report on internal controls over financial reporting

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

Under the supervision and with the participation of management, including the CEO and CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2017 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2017, the internal control over financial reporting was effective.

Changes to internal controls over financial reporting

There were no changes in the Corporation's internal control over financial reporting during the period beginning on January 1, 2017 and ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

CEO and CFO certifications

Perpetual's CEO and CFO have filed with the Canadian securities regulators regarding the quality of Perpetual's public disclosures relating to its fiscal 2017 report filed with the Canadian securities regulators.

CRITICAL ACCOUNTING ESTIMATES

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

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

A change in a critical accounting estimate can have a significant effect on net income as a result of their impact on the depletion rate, provisions, impairments, losses and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant, and equipment, provisions, derivative financial instruments and accounts payable. A complete discussion of critical accounting estimates is included in the notes to the consolidated financial statements at December 31, 2017.

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, natural gas liquids ("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; 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 covenants in 2018 and 2019; the retention of, and benefits to be received from holding the TOU shares (as defined above); 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. The foregoing list of risk factors should not be considered exhaustive.

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

OIL AND GAS ADVISORIES

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

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

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