A Canadian energy producer with a diversified asset portfolio focused on creating both short and long term value through oil and gas based exploration, development, production and marketing.

PERPETUAL ENERGY

The strategic focusing of our asset base, strengthening of our balance sheet, and execution of our growth-oriented capital program in 2017 set the stage for improved performance on all measures in the first six months of 2018. Perpetual posted solid growth in cash flow from operating activities to $19.6 million, seven times higher than the prior year period of $2.4 million, despite the weak and volatile commodity price environment for Western Canadian natural gas. Production growth of 34% relative to the six months ended June 30, 2017, combined with a 27% reduction in per unit operating costs and a 37% reduction in royalties, resulted in a modest improvement in per unit operating netbacks, offsetting the precipitous drop in natural gas prices.

Natural gas prices in Alberta continued to experience weakness during the second quarter of 2018, with average AECO Daily Index prices 58% lower than a year ago. In mid-2017, AECO became disconnected from the North American market as strong Western Canada supply growth faced infrastructure bottlenecks and take away capacity constraints. Perpetual's proactive market diversification strategy implemented in 2017 provided a 90% uplift to prices during the second quarter and importantly, will continue to provide for enhanced risk management through the expected future periods of volatile natural gas prices in Western Canada related to market access constraints.

Heavy oil prices, as measured by the price of Western Canadian Select, were 26% higher than the second quarter of 2017, as global oil inventories are returning to their 5-year average levels. For the coming quarters, Perpetual is strategically directing investment to its heavy oil business.

SECOND QUARTER 2018 HIGHLIGHTS

- Cash flow from operating activities in the second quarter of 2018 was $8.4 million ($0.14/share), up 79% compared to cash flow from operating activities in the prior year period of $4.7 million ($0.08/share).

- Adjusted funds flow in the second quarter of 2018 was $7.8 million ($0.13/share), up 47% over the prior year period of $5.3 million ($0.09/share) due to increased production and lower cash costs, partially offset by lower realized revenue per boe driven by lower commodity prices. Adjusted funds flow was $8.12/boe in the second quarter of 2018, up 30% over the prior year period, and up slightly from $7.94/boe in the first quarter of 2018.

- Production averaged 10,620 boe/d in the second quarter of 2018, up 15% from the comparable period in 2017 driven by the successful Wilrich development program at East Edson executed throughout 2017 and into the first quarter of 2018. With the precipitous drop in the forward market for natural gas prices in Western Canada in early 2018, the East Edson drilling program was paused to preserve value, leading to natural declines in the production base during the second quarter of 2018 as compared to the first quarter.

- Perpetual's market diversification contract contributed $5.1 million to natural gas revenue during the quarter and increased Perpetual's average realized natural gas price by $1.06/Mcf over the AECO Daily Index price. The 40,000 MMBtu/d market diversification contract is priced based on daily index prices at five pricing hubs outside of Alberta that generally track North American NYMEX prices and is effectively mitigating the impact of low and volatile natural gas prices at the Alberta AECO hub.

- Cash costs were $14.19/boe in the second quarter of 2018, down 18% compared to the prior year period due to diligent cost management combined with the impact of increased production at East Edson on a substantially fixed cost base.

- Exploration and development spending in the second quarter of 2018 was seasonally low, totaling $1.7 million, of which 82% was incurred at Mannville to complete and tie-in wells drilled during the first quarter of 2018 and acquire certain crown lands in Eastern Alberta.

- Non-core asset dispositions during the second quarter included the sale of royalty interests and undeveloped land for gross proceeds of $12.1 million, contributing to the 13% reduction in net debt quarter over quarter.

- At June 30, 2018, Perpetual had total net debt of $100.2 million, down $14.9 million (13%) from March 31, 2018, as cash flow from operations exceeded capital expenditures and combined with proceeds from non-core asset sales and an increase in market value of the Tourmaline Oil Corp. ("TOU") share investment.

Production and Operations

- For the six months ended June 30, 2018, spending in Eastern Alberta consisted of a three well (3.0 net) multi-lateral horizontal drilling program, one waterflood injector well conversion, one water disposal well conversion and associated facilities in the Company's Mannville heavy oil property. The disposal facility is working as intended, and is contributing to operating cost improvements. Pressure response is apparent from the injector conversion completed in December of 2017, further validating the success of the Mannville waterfloods. For the balance of 2018, drilling plans in Eastern Alberta include the drilling of five to nine (4.3 – 8.3 net) wells targeting banked waterflood oil, pool extensions, and follow up multi-lateral drilling in early stage pool development, along with several heavy oil reactivations.

- Spending at the East Edson property in West Central Alberta represented 18% of total exploration and development expenditures in the second quarter of 2018, and consisted primarily of maintenance activities associated with reconfiguring equipment for higher Natural Gas Liquids ("NGL") recoveries. East Edson capital activity for the six months ended June 30, 2018 included the drilling of one (1.0 net) Wilrich extended reach horizontal ("ERH") well and the frac and tie-in of two wells drilled in the fourth quarter of 2017. The one well drilled during the first quarter is expected to be frac'd and tied-in to production during the fourth quarter of 2018 to align high initial production rates with higher anticipated winter natural gas prices.

- Second quarter production averaged 10,620 boe/d, up 15% from 9,223 boe/d in the comparative period of 2017, reflecting a 23% increase in natural gas and associated NGL production at East Edson. Compared to the first quarter of 2018, production was down 2,122 boe/d of which 1,050 boe/d was temporarily shut-in. The remainder of the drop related to natural declines stemming from the suspension of development at East Edson. Shut-ins and natural declines were offset somewhat by a 10% increase in heavy oil production at Mannville from the first quarter of 2018 to 943 bbl/d, as production from heavy oil wells drilled during the first quarter ramped up.

- Perpetual voluntarily shut-in an average 350 boe/d of East Edson production during the quarter to take advantage of short-term situations when natural gas could be purchased at minimal cost to satisfy pre-sold volume commitments at attractive margins, resulting in an increase in realized revenue of $0.04/Mcf while retaining reserves for future production. Additionally, approximately 700 boe/d of production was shut-in at East Edson at the request of the Alberta Energy Regulator after the operator of record, Sequoia Resources Corp. ("Sequoia"), filed for bankruptcy. The four well pad at East Edson is 100% owned by Perpetual, but Sequoia was designated operator to facilitate the recovery of Perpetual's gas over bitumen royalty credit amounts held through Sequoia following the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition"). Production remains shut-in pending the completion of the bankruptcy trustee's review of Sequoia's assets and operations. We anticipate production will be restarted later in the fourth quarter of 2018 after the bankruptcy trustee's review has been completed.

- Perpetual's petroleum and natural gas ("P&NG") revenue, before derivatives, for the three months ended June 30, 2018 of $20.8 million increased 5% from the second quarter of 2017 due to a 15% increase in average daily production, partially offset by lower natural gas prices. Compared to the first quarter of 2018, P&NG revenue declined by 11% due to the impact of lower natural gas production at East Edson.

- Natural gas revenue, before derivatives, of $11.3 million in the second quarter of 2018 comprised 54% (Q2 2017 – 64%) of total P&NG revenue while natural gas production was 83% (Q2 2017 – 81%) of total production. Natural gas revenue decreased 11% from $12.7 million in the second quarter of 2017, reflecting the impact of the 58% decrease in AECO Daily Index natural gas prices which more than offset the 18% increase in production volumes.

- Oil revenue of $5.1 million represented 24% (Q2 2017 – 22%) of total P&NG revenue while oil production was 9% (Q2 2017 – 11%) of total production. Oil revenue was 16% higher than the same period in 2017 due to the 26% increase in Western Canadian Select ("WCS") average prices which more than offset the 7% decline in crude oil production. The improving WCS average prices are a function of a higher WTI US$ benchmark price which more than offsets the wider WCS differential and stronger Canadian dollar compared to the prior year period. Compared to the first quarter of 2018, oil revenue was 45% higher, due to the 8% increase in crude oil production and 10% increase in Perpetual's realized oil price per barrel.

- NGL revenue for the second quarter of 2018 of $4.5 million represented 22% (Q2 2017 – 14%) of total P&NG revenue while NGL production was just 8% (Q2 2017 – 7%) of total Company production. NGL revenue increased by 66% over the prior year period as production increased by 21%, reflecting increased natural gas production at East Edson and higher NGL recoveries related to process optimization work, combined with a 37% increase in NGL prices compared to the prior year period. NGL revenue was consistent with the first quarter of 2018, as the 5% decline in production was offset by a corresponding 5% increase in realized NGL pricing.

- Royalty expenses for the quarter ended June 30, 2018 were $2.6 million, 28% lower than the comparable period of 2017, as higher revenue in the current quarter was offset by a decrease in the combined average royalty rate on P&NG revenue from 18.3% in the prior year period to 12.4% in the second quarter of 2018. Sharply lower Alberta gas reference prices and AECO Daily Index prices used to calculate crown and freehold natural gas royalties respectively, contributed to most of the decrease in royalty expense. Royalty expenses also declined by 15% from the first quarter of 2018 for the same reasons mentioned above, with the cost per boe largely unchanged.

- Total production and operating expenses of $4.3 million were down 19% on a unit-of-production basis to $4.45/boe for the second quarter of 2018, compared to $5.52/boe for the comparable period of 2017. On an absolute dollar basis, production and operating costs were down by $0.3 million, despite the 15% increase in production. Increased production at East Edson combined with a low variable cost structure, drove West Central operating costs down to $2.25/boe in the second quarter of 2018 (Q2 2017 – $3.29/boe). Production and operating expenses declined 10% from $4.8 million in Q1 2018, with the cost per boe increasing 7% due to the impact of largely fixed costs on declining production volumes.

- Transportation costs in the second quarter of 2018 were $1.5 million, up 26% from the prior year period due to the increase in firm transportation commitments at East Edson that commenced in December 2017. Transportation costs averaged $1.50/boe at West Central compared to $2.07/boe for production from Eastern Alberta. On a unit-of-production basis, transportation costs were $1.60/boe in the second quarter (Q1 2017 - $1.26/boe), up 10% from the prior year period due to the nature of fixed firm capacity costs relative to lower production.

- Perpetual's operating netback of $13.4 million ($13.85/boe) in the second quarter of 2018 increased 28% from $10.4 million ($12.42/boe) in the comparative period of 2017. This increase was due to the 15% increase in production, combined with a 12% increase in operating netback per boe. Compared to the prior quarter, Perpetual's operating netback increased 8% from $12.87/boe due to increased realized revenue per boe stemming from the Company's realized gains on derivatives and contributions from the natural gas market diversification contract.

Financial Highlights

- During the second quarter of 2018, cash general and administrative ("G&A") expense was $3.5 million, a modest decrease from the prior year period of $3.6 million. Compared to the prior year period, overhead recoveries decreased by 16% as a result of reduced capital spending, offset partially by the increase in expenditures on decommissioning obligations. On a unit-of-production basis, total G&A expense of $3.24/boe for the three months and $3.05/boe for the six months ended June 30, 2018, was down 13% and 23% respectively from the prior year periods due to increasing production. Compared to the first quarter of 2018, total G&A expense decreased by 5% on an absolute dollar basis, as savings on cash G&A were partially offset by lower overhead recoveries resulting from seasonally reduced capital expenditures.

- Total cash interest expense of $2.1 million for the three months ended June 30, 2018 was 11% higher than the prior year period (Q2 2017 – $1.9 million) due to increased debt levels partially offset by dividend income of $0.2 million ($0.09 per TOU share) received from the TOU share investment. Total cash interest expense was consistent with the first quarter of 2018 at $2.1 million, but increased on a unit-of-production basis from $1.84/boe to $2.22/boe due to declining quarter-over-quarter production.

- Net loss for the second quarter of 2018 was $1.3 million ($0.02/share), compared to a net loss of $7.2 million ($0.12/share) in the comparative 2017 period. The improvement from the prior year period reflected stronger operational and capital performance including a 15% increase in production, 18% reduction in cash costs per boe and a 4% reduction in depletion expense per boe, partially offset by a 5% decrease in realized revenue per boe related to lower natural gas prices.

- At June 30, 2018, Perpetual had total net debt of $100.2 million, down $5.8 million from December 31, 2017 and $14.9 million from March 31, 2018 as net cash flow from operations, net proceeds from non-core asset sales completed in the second quarter, and the increased market value of the TOU share investment exceeded capital expenditures during the second quarter and on a year-to-date basis.

- As at June 30, 2018, 63% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow improved slightly during the six months ended June 30, 2018 to 2.7 times at June 30, 2018 (December 31, 2017 – 3.4 times).

2018 STRATEGIC PRIORITIES

During the second quarter of 2018, progress continued to be made to advance Perpetual's top four strategic priorities for 2018 which include:

1. Grow value of Greater Edson liquids-rich gas;
2. Grow value of Eastern Alberta portfolio;
3. Advance high impact opportunities; and
4. Optimize balance sheet for growth.

Grow value of Greater Edson liquids-rich gas

- Production in West Central Alberta, primarily at East Edson, grew 23% relative to the second quarter of 2017 to 8,758 boe/d, comprising 82% of total Company production. The production growth was driven by the successful Wilrich formation development drilling program in 2017 and into the first quarter of 2018.

- Compared to the first quarter of 2018, production decreased by 21% as the East Edson drilling program was paused to preserve value and an average 1,050 boe/d of production was shut-in during the quarter.

- The decrease included the opportunistic shut-in of an average 350 boe/d of East Edson production during the quarter to take advantage of temporary situations when natural gas could be purchased at minimal cost to satisfy pre-sold volume commitments at attractive margins, resulting in an increase in realized revenue of $0.04/Mcf while retaining reserves for future production.

- Further, the decrease also included approximately 700 boe/d of shut-in production from a four well pad at East Edson at the request of the Alberta Energy Regulator after the operator of record, Sequoia, filed for bankruptcy. The four well pad is 100% owned by Perpetual, but Sequoia was designated operator to facilitate the recovery of Perpetual's gas over bitumen royalty credit amounts held through Sequoia following the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition"). Production remains shut-in pending the completion of the bankruptcy trustee's review of Sequoia's assets and operations.

- Spending at East Edson property was just $0.3 million in the second quarter of 2018, consisting primarily of maintenance activities associated with reconfiguring equipment for higher NGL recoveries. East Edson capital activity for the six months ended June 30, 2018 included the drilling of one (1.0 net) Wilrich extended reach horizontal ("ERH") well and the frac and tie-in of two wells drilled in the fourth quarter of 2017. The one ERH well drilled during the first quarter is expected to be frac'd and tied-in to production during the fourth quarter of 2018 to align high initial production rates with higher anticipated winter natural gas prices.

- Increased production at East Edson relative to the 2017 period, combined with a low variable cost structure, drove West Central operating costs down to $2.25/boe in the second quarter of 2018 (Q2 2017 - $3.29/boe). Production and operating expenses at East Edson decreased by 31% on a per boe basis compared to the prior year period due to lower maintenance and repair costs, purchased energy costs, and processing fees combined with the impact of increased production on a substantially fixed operating cost base.

- Operating netbacks in West Central Alberta were $12.33/boe, up 3% relative to Q2 2017 despite the 11% decrease in realized revenue per boe resulting from lower natural gas prices.

- The Company continues to monitor competitor activity and build out future plans to assess secondary development targets at East Edson, including the Cardium, Second White Specks, Viking, Notikewin, Fahler, Ellerslie and Rock Creek formations.

Grow value of Eastern Alberta portfolio

- For the six months ended June 30, 2018, spending in Eastern Alberta of $7.3 million consisted of a three well (3.0 net) multi-lateral horizontal drilling program, one waterflood injector well conversion, one water disposal well conversion and associated facilities in the Company's Mannville heavy oil property. The disposal facility is working as intended, and is contributing to operating cost improvements. Pressure response is apparent from the injector conversion completed in December of 2017, further validating the success of the Mannville waterfloods.

- Crude oil production in Eastern Alberta declined by 9% relative to the second quarter of 2017, reflecting natural declines, partially offset by the strong waterflood response observed in several heavy oil pools. Compared to the first quarter of 2018, crude oil production in Eastern Alberta increased by 10%, reflecting the ramp up of production from heavy oil wells drilled during the first quarter.

- Natural gas production in Eastern Alberta was 5.6 MMcf/d, down 13% from the comparative period of 2017, due to deferred spending on shallow gas recompletion activity given low natural gas prices.

- Close to $0.2 million was spent on abandonment and reclamation projects in Eastern Alberta during the quarter, including well abandonments, pipeline discontinuations and abandonments, and third party environmental spending as well as reclamation work. As part of Perpetual's focus on well and pipeline abandonment and reclamation, five reclamation certificates were received from the Alberta Energy Regulator during the second quarter of 2018 which will result in the cessation of associated property tax and surface lease expenses.

- Production and operating expenses in Eastern Alberta were $14.82/boe during the quarter (Q1 2018 – $18.33/boe; Q2 2017 - $13.01/boe). The first quarter of 2018 saw higher than average well servicing requirements in the Mannville heavy oil operations which increased Eastern Alberta operating costs compared to the prior year period, while negatively affecting production volumes.

- For the balance of 2018, drilling plans in Eastern Alberta include the drilling of five to nine (4.3 – 8.3 net) wells targeting banked waterflood oil, pool extensions, and follow up multi-lateral drilling in early stage pool development, along with several heavy oil reactivations.

Advance high impact opportunities

- Perpetual continued reservoir modelling and simulation work to progress the opportunity for bitumen extraction in the Bluesky formation at Panny using combined solvent with heat. Solvent technology has the potential to augment production rates and recovery and increase capital and operating efficiencies as well as positively enhance environmental performance through reduced emissions and water usage. These learnings will be integrated into a plan for next steps to advance the assessment of the commercial development potential of this large scope Bluesky resource.

- An acquisition involving oil sands leases in the Panny area was closed during the second quarter. The lands are geographically and technically synergistic to the existing Panny pilot project and prospective for cold flow heavy oil in the Bluesky formation.

- Twenty one sections of Crown lands prospective for light oil were purchased at Talbot Lake, approximately 40 km west of Panny.

Optimize balance sheet for growth

- Non-core asset dispositions during the second quarter included the sale of royalty interests and undeveloped land for gross proceeds of $12.1 million. The disposed assets included the Company's 1% gross overriding royalty interest previously retained on 42 net sections (27,722 net acres) of undeveloped oil sands leases in northeast Alberta sold in June 2015 and March 2016. Approximately 5,700 boe of royalty interest reserve volume representing $0.2 million of reserve value was assigned to the royalty lands in the Company's third-party engineering report prepared by McDaniel and Associates Consultants Ltd. as at December 31, 2017. The royalty interests sold contributed less than $0.05 million to adjusted funds flow during the first quarter of 2018.

- In order to protect a base level of adjusted funds flow, Perpetual had commodity price contracts in place during the quarter which resulted in realized gains on derivatives of $1.0 million (Q2 2017 - $0.2 million).

- Perpetual's 40,000 MMBtu/d market diversification contract contributed $5.1 million of incremental revenue and increased Perpetual's average realized natural gas price by $1.06/Mcf over the AECO Daily Index price in the quarter. The five year market diversification contract is priced based on daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) outside of Alberta that generally track North American NYMEX prices. These contracts effectively shift the sales point to the basket of five North American natural gas hub pricing points, diversifying the Company's natural gas price exposure from AECO. Based on current futures prices, Perpetual expects these gas price diversification contracts will provide a significant premium over AECO prices for the remainder of 2018.

- Adjusted funds flow in the second quarter of 2018 was $7.8 million ($0.13/share), up 47% over the prior year period of $5.3 million ($0.09/share) due to increased production and lower cash costs, partially offset by lower realized revenue per boe driven by lower commodity prices. Adjusted funds flow was $8.12/boe in the second quarter of 2018, up 30% over the prior year period, and up slightly from $7.94/boe in the first quarter of 2018.

- At June 30, 2018, Perpetual had total net debt of $100.2 million, down $5.8 million (4%) from December 31, 2017 and $14.9 million (13%) from March 31, 2018 as net cash flow from operations, net proceeds from non-core asset sales completed in the second quarter, and the increased market value of the TOU share investment, exceeded capital expenditures during the second quarter and on a year-to-date basis.

- As at June 30, 2018, 63% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow improved slightly during the six months ended June 30, 2018 to 2.7 times at June 30, 2018 (December 31, 2017 – 3.4 times).

- At June 30, 2018, Perpetual had available liquidity of $36.7 million.

2018 OUTLOOK

Please refer to "Management's Discussion and Analysis – 2018 Outlook" on page 9 of this second quarter 2018 report.

Susan Riddell Rose

Susan Riddell Rose
President and Chief Executive Officer
August 2, 2018

Financial and Operating Highlights

(Cdn$ thousands, except volume and per share amounts)	Three months ended June 30 2018	2017	Change	Six months ended June 30 2018	2017	Change
Financial						
Oil and natural gas revenue	**20,774**	19,728	5%	**44,114**	37,886	16%
Net loss	**(1,325)**	(7,219)	(82%)	**(7,790)**	(21,391)	(64%)
Per share – basic and diluted[2]	**(0.02)**	(0.12)	(83%)	**(0.13)**	(0.38)	(66%)
Cash flow from operating activities	**8,435**	4,728	78%	**19,633**	2,439	705%
Per share[2]	**0.14**	0.08	75%	**0.33**	0.04	725%
Adjusted funds flow[1]	**7,847**	5,265	49%	**16,948**	10,375	63%
Per share[2]	**0.13**	0.09	44%	**0.28**	0.18	56%
Revolving bank debt	**42,752**	4,404	871%	**42,752**	4,404	871%
Senior notes, at principal amount	**32,490**	33,490	(3%)	**32,490**	33,490	(3%)
Term loan, at principal amount	**45,000**	35,000	29%	**45,000**	35,000	29%
TOU share margin loans, at principal amount	**15,714**	35,543	(56%)	**15,714**	35,543	(56%)
TOU share investment	**(38,917)**	(46,489)	(16%)	**(38,917)**	(46,489)	(16%)
Net working capital deficiency[1]	**3,123**	6,389	(51%)	**3,123**	6,389	(51%)
Total net debt[1]	**100,162**	68,337	47%	**100,162**	68,337	47%
Net capital expenditures						
Capital expenditures	**2,031**	4,006	(49%)	**16,928**	28,596	(41%)
Net payments (proceeds) on acquisitions and dispositions	**(7,012)**	609	(1,251%)	**(6,086)**	772	(888%)
Net capital expenditures	**(4,981)**	4,615	(208%)	**10,842**	29,368	(63%)
Common shares outstanding *(thousands)*[3]						
End of period	**60,369**	59,035	2%	**60,369**	59,035	2%
Weighted average – basic and diluted	**59,876**	59,045	1%	**59,612**	56,769	5%
Operating						
Average production						
Natural gas *(MMcf/d)*	**53.1**	45.1	18%	**59.4**	42.9	38%
Oil *(bbl/d)*	**971**	1,049	(7%)	**936**	962	(3%)
NGL *(bbl/d)*	**806**	665	21%	**827**	573	44%
Total *(boe/d)*	**10,620**	9,223	15%	**11,675**	8,686	34%
Average prices						
Realized natural gas price *($/Mcf)*	**2.62**	3.18	(18%)	**2.64**	4.05	(35%)
Realized oil price *($/bbl)*	**53.26**	43.91	21%	**50.89**	38.24	33%
Realized NGL price *($/bbl)*	**60.77**	44.28	37%	**59.16**	46.54	27%
Wells drilled						
Natural gas – gross (net)	**1 (1.0)**	1 (1.0)		**1 (1.0)**	7 (7.0)	
Oil – gross (net)	**3 (3.0)**	–		**3 (3.0)**	4 (3.3)	
Total – gross (net)	**4 (4.0)**	1 (1.0)		**4 (4.0)**	11 (10.3)	

(1) These are non-GAAP measures. Please refer to "Non-GAAP Measures" below.
(2) Based on weighted average common shares outstanding for the period.
(3) All common shares are presented net of shares held in trust.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc.'s ("Perpetual", the "Company" or the "Corporation") operating and financial results for the three and six months ended June 30, 2018 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's condensed interim consolidated financial statements and accompanying notes for the three and six months ended June 30, 2018 as well as audited consolidated financial statements and accompanying notes for the years ended December 31, 2017 and 2016. The MD&A should be read in conjunction with the Corporation's MD&A for the year ended December 31, 2017 as disclosure which is unchanged from the December 31, 2017 MD&A has not been duplicated herein. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). 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 August 2, 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 per boe", "available liquidity", "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 (used in) operating activities as defined by GAAP, these terms are useful supplemental measures to evaluate performance. Users are cautioned however that these measures should not be construed as an alternative to net income (loss) or net cash flows from (used in) operating activities determined in accordance with GAAP as an indication of Perpetual's performance and may not be comparable with the calculation of similar measurements by other entities.

Adjusted funds flow: Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations and meet its financial obligations. Adjusted funds flow is calculated based on cash flows from (used in) operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations since Perpetual believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. The Company has also deducted the change in gas over bitumen royalty financing from adjusted funds flow, in order to present these payments net of gas over bitumen royalty credits. These payments are indexed to gas over bitumen royalty credits and are recorded as a reduction to the Corporation's gas over bitumen royalty financing obligation in accordance with IFRS. Additionally, the Company has excluded payments of restructuring costs associated with the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition"), which management considers to not be related to cash flow from operating activities. Restructuring costs include employee downsizing costs and surplus office lease obligations. Commencing in the first quarter of 2018, the Company no longer excludes 'exploration and evaluation – geological and geophysical costs' (Q2 2018 – nil; and Q2 2017 – recovery of $0.02 million) from the calculation of adjusted funds flow as these costs are no longer significant to the Company's business. The calculation of adjusted funds flow for comparative periods has been adjusted to give effect to this change.

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

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

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

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except per share and per boe amounts*)	**2018**	2017	**2018**	2017
Net cash flows from (used in) operating activities	**8,435**	4,728	**19,633**	2,439
Changes in non-cash working capital	**(731)**	718	**(3,127)**	7,026
Expenditures on decommissioning obligations	**353**	(26)	**906**	537
Change in gas over bitumen royalty financing	**(260)**	(710)	**(699)**	(1,526)
Payments of restructuring costs	**50**	555	**235**	1,899
Adjusted funds flow	**7,847**	5,265	**16,948**	10,375
Adjusted funds flow per share	**0.13**	0.09	**0.28**	0.18
Adjusted funds flow per boe	**8.12**	6.27	**8.02**	6.60

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

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

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except per boe amounts*)	**2018**	2017	**2018**	2017
Royalties	**2,590**	3,606	**5,653**	6,708
Production and operating	**4,304**	4,634	**9,076**	9,235
Transportation	**1,546**	1,226	**2,989**	2,241
General and administrative	**3,130**	3,142	**6,441**	6,243
Cash interest expense and income	**2,143**	1,921	**4,258**	3,818
Cash costs	**13,713**	14,529	**28,417**	28,245
Cash costs per boe	**14.19**	17.31	**13.45**	17.97

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 revolving bank debt including net working capital deficiency (surplus). Net debt includes the carrying value of net bank debt, the principal amount of the term loan, the principal amount of the TOU share margin loan 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 share investment, TOU share margin loan, revolving bank debt, and current portion of provisions.

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

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, including 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, basis differentials, and forward foreign exchange sales. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices and foreign exchange rates, and as such, any related realized gains or losses are considered part of the Corporation's realized price.

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

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

SECOND QUARTER 2018 HIGHLIGHTS

In response to the material weakening of AECO forward natural gas prices, Perpetual announced on May 8, 2018, changes to its 2018 capital plan designed to preserve the value of its liquids-rich natural gas reserves by deferring additional 2018 development drilling at East Edson in West Central Alberta and focusing on more economic heavy oil projects at Mannville in Eastern Alberta, resulting in a net reduction to the 2018 capital budget to $21 - $25 million.

Exploration and development spending for the second quarter of 2018 was $1.7 million, of which 82% was incurred at Mannville to complete and tie-in wells drilled during the first quarter of 2018 and acquire certain crown lands in Eastern Alberta.

Production averaged 10,620 boe/d in the second quarter of 2018, up 15% from the comparable period in 2017 driven by the 2017 and Q1 2018 capital programs. Compared to the first quarter of 2018, production was down 17%. Perpetual opportunistically shut-in an average 350 boe/d of East Edson production during the quarter to take advantage of temporary situations when natural gas could be purchased at minimal cost to satisfy pre-sold volume commitments at attractive margins, resulting in an increase in realized revenue of $0.04/Mcf while retaining reserves for future production. Additionally, approximately 700 boe/d of production was shut-in at East Edson at the request of the Alberta Energy Regulator after the operator of record, Sequoia Resources Corp. ("Sequoia"), filed for bankruptcy. The four well pad at East Edson is 100% owned by Perpetual, but Sequoia was designated operator to facilitate the recovery of Perpetual's gas over bitumen royalty credit amounts retained by Sequoia following the Shallow Gas Disposition. Production remains shut-in, pending the completion of the bankruptcy trustee's review of Sequoia's assets and operations. Natural declines contributed to the remaining decrease in production from first quarter 2018 levels.

Realized revenue was $22.58/boe in the second quarter of 2018 compared to $23.70/boe in the prior year period, down 5% as the impact of the 58% reduction in the AECO Daily Index natural gas price from the comparative period was largely offset by higher sales prices realized through Perpetual's natural gas market diversification contract to markets outside of Alberta, combined with higher oil and NGL selling prices in the second quarter of 2018. Deliveries to the market diversification contract commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018. Natural gas comprised 83% of production on a boe basis in the second quarter of 2018 compared to 81% in the prior year period.

Cash costs were $14.19/boe in the second quarter of 2018, down 18% compared to the prior year period due to diligent cost management combined with the impact of increased production at East Edson on a substantially fixed cost base. Operating costs at West Central Alberta were $2.25/boe for the three months ended June 30, 2018.

Net loss for the second quarter of 2018 was $1.3 million ($0.02/share), compared to a net loss of $7.2 million ($0.12/share) in the comparative period of 2017. The improvement from the prior year period reflected stronger operational and capital performance, including the 15% increase in production, an 18% reduction in cash costs per boe and a 4% reduction in depletion expense per boe, partially offset by a 5% decrease in realized revenue per boe related to lower natural gas prices.

Cash flow from operating activities in the second quarter of 2018 was $8.4 million ($0.14/share) compared to cash flow from operating activities in the prior year period of $4.7 million ($0.08/share).

Adjusted funds flow in the second quarter of 2018 was $7.8 million ($0.13/share), up 49% over the prior year period of $5.3 million ($0.09/share) due to increased production and lower cash costs, and despite lower revenue per boe. Adjusted funds flow was $8.12/boe in the second quarter of 2018, up 30% over the prior year period.

Net proceeds from dispositions of oil and gas properties during the second quarter of $12.1 million were realized from the sale of non-core royalty interests and exploration and evaluation properties. Net proceeds were used to repay revolving bank debt.

OUTLOOK

Perpetual has increased its 2018 capital expenditure guidance from a range of $21 to $25 million provided in a press release dated May 8, 2018 ("Previous Guidance") to $25 to $30 million ($8 to $13 million for the remainder of 2018) and increased its planned Mannville heavy oil drilling in the second half of 2018 to five to nine wells (4.3 - 8.3 net) from two wells (1.3 net) previously. At East Edson, one horizontal well drilled in the first quarter will be completed and tied-in during the fourth quarter of 2018 to align high initial production rates with higher anticipated winter natural gas prices. Additional development drilling is ready to activate if AECO forward prices normalize above $2.00/Mcf. Additionally, decommissioning expenditures are anticipated to be $1.0 to $1.5 million for the remainder of 2018, consistent with Previous Guidance. Capital spending during the remainder of 2018 will be funded through adjusted funds flow.

Production for 2018 is expected to be 10,500 boe/d to 11,000 boe/d, consistent with Previous Guidance. East Edson production that has been shut-in due to the Sequoia bankruptcy proceedings, is anticipated to be restarted during the fourth quarter after the bankruptcy trustee's review has been completed. For the April through October period, Perpetual has fixed the price on 20,000 GJ/d at $1.74/GJ AECO with the remainder of its production sold at daily index prices at the Chicago, Dawn, Empress, Malin and Michcon markets through its 40,000 MMBtu/d market diversification contract. If AECO prices temporarily weaken, Perpetual's fixed price AECO position provides the ability to shut-in production and purchase gas to deliver against pre-sold commitments while preserving reserves and future deliverability capability. Perpetual has costless collar and fixed price oil sales arrangements in place to sell 750 bbl/d at an average US$60.71/bbl for the remainder of 2018. Additionally, Perpetual has fixed the US$/Cdn$ exchange rate on approximately 65% of its US$ denominated sales at a rate of $1.301 for the remainder of 2018.

Cash costs of $14.00 to $15.00/boe are anticipated for 2018, consistent with Previous Guidance.

Adjusted funds flow for 2018 is anticipated to be in the $26 to $30 million range ($11 to $15 million for the remainder of 2018), up slightly from Previous Guidance of $25 to $28 million due to improved performance in the second quarter.

Guidance assumptions are as follows:

	Current Guidance	Previous Guidance
Exploration and development expenditures (*$ millions*)	**$25 - $30**	$21 - 25
2018 cash costs (*$/boe*)	**$14.00 - $15.00**	$14.00 - $15.00
2018 average daily production (*boe/d*)	**10,500 - 11,000**	10,500 - 11,000
2018 average production mix (*%*)	**16% oil and NGL**	15% oil and NGL

Commodity price assumptions reflect market price levels as follows:

	Current Guidance	Previous Guidance
2018 average NYMEX natural gas price (*US$/MMBtu*)	**$2.85**	$2.86
2018 average NYMEX to AECO basis differential (*US$/MMBtu*)	**($1.68)**	($1.73)
2018 average West Texas Intermediate ("WTI") oil price (*US$/bbl*)	**$65.24**	$65.55
2018 average Western Canadian Select ("WCS") differential (*US$/bbl*)	**($23.62)**	($22.30)
2018 average exchange rate (US$1.00 = Cdn$)	**$1.298**	$1.277

Year end 2018 net debt (net of the current market value of the Company's TOU share investment of approximately $40 million) is forecast at $98 - $103 million, down from Previous Guidance of $105 - $110 million, due to net proceeds received from non-core asset dispositions during the second quarter and an increase in the current market value of TOU shares, offset by modestly higher capital spending. Current guidance is based on the following assumptions:

- Net debt at June 30, 2018 of $100.2 million
- Adjusted funds flow for the remainder of 2018 of $11 to $15 million
- Capital spending for the remainder of 2018 of $8 to $13 million
- Decommissioning expenditures for the remainder of 2018 of $1.0 to $1.5 million
- Shallow Gas Disposition – fixed marketing obligation payment of $3.1 million in the third quarter of 2018

SECOND QUARTER FINANCIAL AND OPERATING RESULTS

Capital expenditures

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Exploration and development	**1,737**	3,981	**16,584**	28,544
Other	**294**	25	**344**	52
Capital expenditures	**2,031**	4,006	**16,928**	28,596
Acquisitions	**610**	–	**610**	208
Net payments (proceeds) on dispositions	**(7,622)**	609	**(6,696)**	564
Total	**(4,981)**	4,615	**10,842**	29,368

Exploration and development spending by area

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
West Central	**307**	3,448	**9,249**	21,973
Eastern Alberta	**1,430**	533	**7,335**	6,571
Total	**1,737**	3,981	**16,584**	28,544

Wells drilled by area

	Three months ended June 30,		Six months ended June 30,	
(gross/net)	**2018**	2017	**2018**	2017
West Central	**-/-**	1/1.0	**1/1.0**	6/6.0
Eastern Alberta	**-/-**	-/-	**3/3.0**	5/4.3
Total	**-/-**	1/1.0	**4/4.0**	11/10.3

Perpetual's exploration and development spending in the second quarter of 2018 was seasonally low, totaling $1.7 million. Capital expenditures included completion and tie-in costs from the first quarter heavy oil drilling program at Mannville, facilities work, and the cost to acquire certain crown lands in Northern Alberta.

Spending at the East Edson property in West Central Alberta represented 18% of total exploration and development expenditures in the second quarter of 2018, and consisted primarily of maintenance activities associated with reconfiguring equipment for higher NGL recoveries. East Edson capital activity for the six months ended June 30, 2018 included the drilling of one (1.0 net) Wilrich extended reach horizontal ("ERH") well and the frac and tie-in of two wells drilled in the fourth quarter of 2017. The one well drilled during the first quarter is expected to be frac'd and tied-in to production during the fourth quarter of 2018 to align high initial production rates with higher anticipated winter natural gas prices.

For the six months ended June 30, 2018, spending in Eastern Alberta consisted of a three well (3.0 net) multi-lateral horizontal drilling program, one waterflood injector well conversion, one water disposal well conversion and associated facilities in the Company's Mannville heavy oil property. The disposal facility is working as intended, and is contributing to operating cost improvements. Pressure response is apparent from the injector conversion completed in December of 2017, further validating the success of the Mannville waterfloods. For the balance of 2018, drilling plans in Eastern Alberta include the drilling of five to nine (4.3 – 8.3 net) wells targeting banked waterflood oil, pool extensions, and follow up multi-lateral drilling in early stage pool development, along with up to 5 oil well reactivations.

Dispositions

Proceeds (payments) on dispositions

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Proceeds from dispositions of oil and gas properties	**12,149**	–	**12,152**	436
Proceeds from retained shallow gas marketing arrangements[(1)]	**–**	331	**–**	869
Payments on retained shallow gas marketing arrangements[(1)]	**(4,527)**	(940)	**(5,456)**	(1,869)
Net proceeds (payments) on dispositions	**7,622**	(609)	**6,696**	(564)

Gain (loss) on dispositions

($ thousands)	Three months ended June 30, **2018**	2017	Six months ended June 30, **2018**	2017
Proceeds from dispositions of oil and gas properties	**12,149**	–	**12,152**	436
Carrying amount of PP&E and E&E disposed, net of ARO	**(11,415)**	–	**(11,415)**	(8)
Realized gain from retained shallow gas marketing arrangements[1]	**–**	331	**–**	869
Unrealized loss on retained shallow gas marketing arrangements[1]	**–**	(1,363)	**(874)**	(4,520)
Gain (loss) on dispositions	**734**	(1,032)	**(137)**	(3,223)

(1) Related to the Shallow Gas Disposition.

Dispositions during the three and six months ended June 30, 2018 included the sale of non-core royalty interests and exploration and evaluation properties for gross proceeds of $12.1 million, resulting in a net gain on oil and gas properties of $0.7 million. Included in the gain was $0.4 million in liabilities related to decommissioning obligations associated with the sale of non-core properties.

On October 1, 2016, Perpetual sold 5,900 boe/d of mature, high-cost shallow gas assets in east central and northeast Alberta for nominal cash consideration that also included retained marketing arrangements whereby the Company provided natural gas floor price protection at $2.58/GJ to the purchaser and retained price participation to the extent average monthly AECO prices exceed $2.81/GJ on 33,611 GJ/d through to August 31, 2018. The Company entered into marketing arrangements prior to closing to fix the cost of the floor price protection through to March 31, 2018. Realized and unrealized gains and losses on these marketing arrangements are recognized as adjustments to gains/losses on dispositions and included as cash flows from investing activities on the consolidated statement of cash flows. In the first quarter of 2018, Perpetual fixed the cost of the floor price protection for the remaining period from April 1, 2018 to August 31, 2018 at a cost of $7.6 million, resulting in an unrealized loss of $0.9 million. Payments of $4.5 million were made during the second quarter, with $3.1 million remaining to be paid in the third quarter.

Expenditures on decommissioning obligations

During the three months ended June 30, 2018, Perpetual spent $0.4 million (Q2 2017 – $nil) on abandonment and reclamation projects. As part of Perpetual's focus on well and pipeline abandonment and reclamation, five reclamation certificates were received from the Alberta Energy Regulator during the second quarter of 2018 (Q2 2017 – nil) which will result in the cessation of associated property tax and surface lease expenses. For the six months ended June 30, 2018, Perpetual spent $0.9 million (2017 – $0.5 million) on abandonment and reclamation projects and received 13 reclamation certificates, compared to 27 in the prior year period. Perpetual will continue to execute an internally managed asset retirement program at Mannville in the second half of 2018.

Operating netbacks

The following table highlights Perpetual's operating netbacks for the three and six months ended June 30, 2018 and 2017:

	Three months ended June 30, 2018			Three months ended June 30, 2017		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue[1]	**14,818**	**5,956**	**20,774**	13,469	6,259	19,728
Realized gains on derivatives[2]	**–**	**–**	**1,048**	–	–	162
Royalties	**(1,999)**	**(591)**	**(2,590)**	(2,841)	(765)	(3,606)
Production and operating expenses	**(1,794)**	**(2,510)**	**(4,304)**	(2,123)	(2,511)	(4,634)
Transportation costs	**(1,196)**	**(350)**	**(1,546)**	(767)	(459)	(1,226)
Total operating netback	**9,829**	**2,505**	**13,382**	7,738	2,524	10,424

	Six months ended June 30, 2018			Six months ended June 30, 2017		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue[1]	**33,908**	**10,206**	**44,114**	26,521	11,365	37,886
Realized gains on derivatives[2]	**–**	**–**	**1,739**	–	–	909
Royalties	**(4,578)**	**(1,075)**	**(5,653)**	(5,535)	(1,173)	(6,708)
Production and operating expenses	**(3,837)**	**(5,239)**	**(9,076)**	(4,215)	(5,020)	(9,235)
Transportation costs	**(2,324)**	**(665)**	**(2,989)**	(1,369)	(872)	(2,241)
Total operating netback	**23,169**	**3,227**	**28,135**	15,402	4,300	20,611

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

	Three months ended June 30, 2018			Three months ended June 30, 2017		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**8,758**	**1,862**	**10,620**	7,102	2,121	9,223
Total petroleum and natural gas revenue	**18.59**	**35.16**	**21.50**	20.84	32.43	23.51
Realized gains on derivatives	**–**	**–**	**1.08**	–	–	0.19
Royalties	**(2.51)**	**(3.49)**	**(2.68)**	(4.40)	(3.96)	(4.30)
Production and operating expenses	**(2.25)**	**(14.82)**	**(4.45)**	(3.29)	(13.01)	(5.52)
Transportation costs	**(1.50)**	**(2.07)**	**(1.60)**	(1.19)	(2.38)	(1.46)
Total operating netback	**12.33**	**14.78**	**13.85**	11.96	13.08	12.42

($/boe)	Six months ended June 30, 2018 West Central	Eastern	Total	Six months ended June 30, 2017 West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**9,917**	**1,758**	**11,675**	6,653	2,033	8,686
Total petroleum and natural gas revenue	**18.89**	**32.06**	**20.88**	22.02	30.89	24.10
Realized gains on derivatives	**–**	**–**	**0.82**	–	–	0.58
Royalties	**(2.55)**	**(3.38)**	**(2.68)**	(4.60)	(3.19)	(4.27)
Production and operating expenses	**(2.14)**	**(16.46)**	**(4.29)**	(3.50)	(13.64)	(5.87)
Transportation costs	**(1.29)**	**(2.09)**	**(1.41)**	(1.14)	(2.37)	(1.43)
Total operating netback	**12.91**	**10.13**	**13.32**	12.78	11.69	13.11

Perpetual's operating netback of $13.4 million ($13.85/boe) in the second quarter of 2018 increased 28% from $10.4 million ($12.42/boe) in the comparative period of 2017. This increase was due to the 15% increase in production, combined with a 12% increase in operating netback per boe. The increase in operating netback per boe for the second quarter of 2018 compared to the prior year period reflects a 38% decline in royalties and 19% reduction in operating costs per boe, partially offset by the 10% increase in per unit transportation costs and 5% reduction in realized revenue per boe. The decrease in realized revenue per boe compared to the prior year period is due to the 58% decrease in the AECO Daily Index natural gas price, partially offset by higher prices realized from Perpetual's natural gas market diversification contract, and higher oil and NGL prices in the second quarter of 2018.

Perpetual's operating netback of $28.1 million ($13.32/boe) for the six months ended June 30, 2018 increased 37% from $20.6 million ($13.11/boe) in the comparative period of 2017. This increase was due to the 34% increase in production, combined with the modest increase in operating netback per boe.

Production

	Three months ended June 30, **2018**	2017	Six months ended June 30, **2018**	2017
Natural gas (*MMcf/d*)				
Eastern Alberta	**5.6**	6.4	**5.2**	6.4
West Central	**47.5**	38.7	**54.2**	36.5
Total natural gas[(1)]	**53.1**	45.1	**59.4**	42.9
Crude oil (*bbl/d*)				
Eastern Alberta[(2)]	**943**	1,032	**901**	945
West Central	**28**	17	**35**	17
Total crude oil	**971**	1,049	**936**	962
Total NGL (*bbl/d*)[(3)]	**806**	665	**827**	573
Total production (*boe/d*)	**10,620**	9,223	**11,675**	8,686

(1) Natural gas production yields a heat content of $1.17 GJ/Mcf (2017 – $1.16), resulting in higher realized natural gas prices per Mcf. 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.

Second quarter production averaged 10,620 boe/d, up 15% from 9,223 boe/d in the comparative period of 2017, reflecting a 23% increase in natural gas and associated NGL production at East Edson driven by the 2017 and Q1 2018 capital programs. Compared to the first quarter of 2018, production was down 17% (19% decline in natural gas, 2% increase in oil and NGL's). Perpetual opportunistically shut-in an average 350 boe/d of East Edson production during the quarter to take advantage of temporary situations when natural gas could be purchased at minimal cost to satisfy pre-sold volume commitments at attractive margins, resulting in an increase in realized revenue of $0.04/Mcf while retaining reserves for future production. Additionally, approximately 700 boe/d of production was shut-in at East Edson at the request of the Alberta Energy Regulator after the operator of record, Sequoia Resources Corp., filed for bankruptcy. The four well pad at East Edson is 100% owned by Perpetual, but Sequoia was designated operator to facilitate the recovery of Perpetual's gas over bitumen royalty credit amounts retained by Sequoia following the Shallow Gas Disposition. Production remains shut-in, pending the completion of the bankruptcy trustee's review of Sequoia's assets and operations. Natural declines contributed to the remaining decrease in production from first quarter 2018 levels.

NGL yields at East Edson increased to 17 bbls per MMcf of natural gas in the second quarter from 14 bbls per MMcf in the first quarter of 2018, due to the reconfiguration of plant processing equipment and higher NGL production from wells tied in and reactivated during the first quarter.

Crude oil production in Eastern Alberta was 10% higher than the first quarter of 2018, as wells drilled during the first quarter of 2018 were on production for the entire period.

For the six months ended June 30, 2018, production increased by 34% to 11,675 boe/d compared to 8,686 boe/d in the prior year period. Production levels increased through 2017 with successful drilling results from increased capital expenditures.

Production at East Edson is expected to decline through the summer months before increasing in the fourth quarter when the well drilled in the first quarter is frac'd and tied in for production, and the four well East Edson pad is anticipated to be restarted.

Commodity Prices

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
Reference prices				
NYMEX Daily Index (*US$/MMBtu*)	**2.80**	3.18	**2.90**	3.25
AECO Daily Index (*$/GJ*)	**1.12**	2.64	**1.54**	2.60
AECO Daily Index ($/Mcf)(1)	**1.18**	2.79	**1.63**	2.74
Alberta Gas Reference Price (*$/GJ*)(2)	**0.93**	2.47	**1.31**	2.48
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**67.88**	48.28	**65.37**	50.10
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(19.27)**	(11.13)	**(21.77)**	(12.85)
WCS average (Cdn*$/bbl*)(3)	**62.70**	49.78	**55.81**	49.54
Average Perpetual prices				
Natural gas (*$/Mcf*)(1)				
AECO Daily Index	**1.18**	2.79	**1.63**	2.74
Heat content premium(4)	**0.13**	0.29	**0.18**	0.28
Market diversification contracts	**1.06**	–	**0.69**	–
Realized gains (losses) on financial and physical gas derivatives	**0.25**	0.18	**0.04**	0.96
Realized gains (losses) on prompt month price optimization	**–**	(0.08)	**0.10**	0.07
Realized natural gas price (*$/Mcf*)(5)	**2.62**	3.18	**2.64**	4.05
Percent of AECO Daily Index	**222**	114	**162**	148
Realized oil price (*$/bbl*)(5)	**53.26**	43.91	**50.89**	38.24
Natural gas liquids ("NGL") (*$/bbl*)	**60.77**	44.28	**59.16**	46.54

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.
(3) Derived internally using the Bank of Canada average foreign exchange rate of US$1.00 = Cdn$1.29 for the three months ended June 30, 2018 (Q2 2017 – $1.34) and $1.28 for the six months ended June 30, 2018 (2017 – $1.33).
(4) Realized natural gas prices are at a premium to the AECO Daily Index due to higher heat content. For the three and six months ended June 30, 2018, Perpetual received an 11% premium to the AECO Daily Index (Q2 2017 – 10%).
(5) Realized natural gas and oil prices include physical forward sales contracts for which delivery was made during the reporting period, and realized gains and losses on financial derivatives and foreign exchange contracts.

Despite increased demand due to a colder year-over-year winter and warmer year-over-year May and June, higher North American production caused NYMEX natural gas prices to decrease 11% from US$3.25/MMBtu for the six months ended June 30, 2017 to an average of US$2.90/MMBtu for the six month period ended June 30, 2018. In comparison, the AECO Daily Index prices decreased 41% from $2.60/GJ for the six months ended June 30, 2017 to $1.54/GJ for the six month period ended June 30, 2018. In mid-2017, AECO became disconnected from the North American market as production growth in the Western Canadian Sedimentary Basin outpaced access to markets outside of Western Canada and market demand, aggravated by the management of pipeline maintenance activities.

The increase of WTI to US$65.37/bbl for the six month period ended June 30, 2018 from US$50.10/bbl for the six months ended June 30, 2017 was related to the reduction in global oil inventories back to 5 year average levels by the end of June 30, 2018, stemming from the OPEC production cuts that began January 1, 2017, along with other global declines. The WCS differential widened from an average US$12.85/bbl in the first half of 2017 to US$21.77/bbl in the first half of 2018 due to increased heavy oil and bitumen production in Western Canada combined with pipeline capacity constraints that restricted access to markets outside of Western Canada.

Perpetual's realized natural gas price, including derivatives, decreased 18% to $2.62/Mcf for the second quarter of 2018 from $3.18/Mcf in the comparative period of 2017, representing 222% of the AECO Daily Index price compared to 114% in the prior year period. Realized gains on financial and physical gas derivatives, along with prompt month price optimization operations added $0.25/Mcf to the realized price in the second quarter of 2018 (Q2 2017 – $0.10/Mcf gain), while the 40,000 MMBtu/d market diversification contract added $1.06/Mcf (Q2 2017 – nil) on the relative strength of NYMEX daily index prices compared to AECO. During the second quarter of 2018, the average heat content conversion ratio for Perpetual's natural gas production was 1.17 GJ:1 Mcf compared to 1.16 GJ:1 Mcf in the comparative period of 2017. This increase reflects the larger percentage of total gas production from East Edson, which yields higher heat content gas compared to Perpetual's other production areas. Market diversification contract sales commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018.

Perpetual's realized oil price of $53.26/bbl was 21% higher than the second quarter of 2017 and included realized losses on crude oil derivative contracts of $0.4 million ($4.04/bbl). Realized prices in the second quarter of 2017 were reduced by $2.01/bbl associated with realized hedging losses in the period.

Perpetual's realized NGL price for the second quarter of 2018 reached $60.77/bbl, up 37% from the second quarter of 2017, reflecting an increase in all NGL component prices which closely correlate with the increase in WTI light oil prices (41%) over the prior year period. Perpetual's average NGL sales composition for the second quarter ended June 30, 2018 consisted of 69% condensate, a slight increase from the prior year period (Q2 2017 – 65%).

Revenue

($ thousands, except as noted)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Petroleum and natural gas revenue				
Natural gas[(1)]	**11,254**	12,667	**26,705**	25,230
Oil	**5,063**	4,380	**8,553**	7,831
NGL	**4,457**	2,681	**8,856**	4,825
Total petroleum and natural gas revenue	**20,774**	19,728	**44,114**	37,886
Realized gains (losses) on derivatives[(2)]	**1,048**	162	**1,739**	909
Realized revenue	**21,822**	19,890	**45,853**	38,795
Unrealized gains (losses) on derivatives	**(2,778)**	1,129	**(5,104)**	4,375
Total revenue	**19,044**	21,019	**40,749**	43,170
Realized revenue *($/boe)*	**22.58**	23.70	**21.70**	24.68
Total revenue *($/boe)*	**19.71**	25.04	**19.28**	27.46

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

Perpetual's petroleum and natural gas ("P&NG") revenue, before derivatives, for the three months ended June 30, 2018 of $20.8 million increased 5% from the second quarter of 2017 due to a 15% increase in average daily production, partially offset by lower natural gas prices. For the six month period ended June 30, 2018, P&NG revenue increased by 16% compared to the prior year period, following the 34% increase in average daily production over the same period.

Natural gas revenue, before derivatives, of $11.3 million in the second quarter of 2018 comprised 54% (Q2 2017 – 64%) of total petroleum and natural gas revenue and 83% (Q2 2017 – 81%) of total production. Natural gas revenue decreased 11% from $12.7 million in the second quarter of 2017, reflecting the impact of the 58% decrease in AECO Daily Index natural gas prices which more than offset the 18% increase in production volumes driven by the 2017 and Q1 2018 East Edson capital programs. Perpetual's 40,000 MMBtu/d market diversification contract contributed $5.1 million of incremental revenue and increased Perpetual's average realized natural gas price by $1.06/Mcf over the AECO Daily Index price in the quarter. The market diversification contract is priced based on daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) outside of Alberta that generally track North American NYMEX prices. For the six month period ended June 30, 2018, natural gas revenue increased by 6% compared to the prior year period, primarily due to the 38% increase in natural gas production, partially offset by the 41% decline in AECO Daily Index prices over the same period.

Oil revenue of $5.1 million represented 24% (Q2 2017 – 22%) of total petroleum and natural gas revenue while oil production was 9% (Q2 2017 – 11%) of total production. Oil revenue was 16% higher than the same period in 2017 due to the 26% increase in WCS average prices which more than offset the 7% decline in crude oil production. The improving WCS average prices are a function of a higher WTI US$ benchmark price which more than offsets the wider WCS differential and stronger Canadian dollar compared to the prior year period. For the six month period ended June 30, 2018, oil revenue increased by 9% compared to the prior year period, primarily due to the 30% increase in WTI light oil prices which more than offset the impact of a widening WCS differential and slight decrease in oil production over the same period.

NGL revenue for the second quarter of 2018 of $4.5 million represented 22% (Q2 2017 – 14%) of total petroleum and natural gas revenue while NGL production was just 8% (Q2 2017 – 7%) of total Company production. NGL revenue increased by 66% over the prior year period as production increased by 21%, reflecting increased natural gas production at East Edson and higher NGL recoveries related to process optimization work at the Company's 100% owned and operated gas plant, combined with a 37% increase in NGL prices compared to the prior year period. For the six month period ended June 30, 2018, NGL revenue increased by 84% compared to the prior year period, due to the 44% increase in production combined with a 27% increase in realized NGL prices.

Realized gains on derivatives totaled $1.0 million for the second quarter of 2018, compared to gains of $0.2 million for the same period of 2017. The realized gain in the current period was comprised of $1.4 million from natural gas derivatives (Q2 2017 – $0.4 million), offset partially by losses of $0.4 million from oil derivatives (Q2 2017 – $0.2 million).

Perpetual recorded unrealized losses on derivatives of $2.8 million during the second quarter of 2018 compared to unrealized gains of $1.1 million for the same period in 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. Commodity price management contracts are actively managed in accordance with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

Royalties

($ thousands, except as noted)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Crown	**627**	754	**1,428**	1,232
Freehold and overriding[(1)]	**1,963**	2,852	**4,225**	5,476
Total	**2,590**	3,606	**5,653**	6,708
Crown (*% of P&NG revenue*)	**3.0**	3.8	**3.2**	3.3
Freehold and overriding (*% of P&NG revenue*)	**9.4**	14.5	**9.6**	14.5
Total (*% of P&NG revenue*)	**12.4**	18.3	**12.8**	17.8
$/boe	**2.68**	4.30	**2.68**	4.27

(1) Includes $1.2 million in gross overriding royalty payments at East Edson for the three months ended June 30, 2018 (Q2 2017 – $2.1 million) and $2.8 million for the six months ended June 30, 2018 (2017 – $4.1 million).

Royalty expenses for the quarter ended June 30, 2018 were $2.6 million, 28% lower than the comparable period of 2017, as higher revenue in the current quarter was offset by a decrease in the combined average royalty rate on P&NG revenue from 18.3% in the prior year period to 12.4% in the second quarter of 2018. Sharply lower Alberta gas reference prices and AECO Daily Index prices used to calculate crown and freehold natural gas royalties respectively, contributed to most of the decrease in royalty expense. Pursuant to Perpetual's East Edson agreements, the partner is entitled to a gross overriding royalty equivalent to a maximum of 5.6 MMcf/d of natural gas from the East Edson property plus oil and associated NGL's on a monthly basis. The East Edson royalty is taken in kind, but calculated based on the AECO Daily Index natural gas price. As East Edson natural gas production has increased by 23% in the second quarter of 2018 compared to the prior year period, the fixed nature of the gross overriding royalty has resulted in a decreased expense on a percentage of revenue and unit-of-production basis.

Production and operating expenses

($ thousands, except as noted)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Production and operating expenses	**4,304**	4,634	**9,076**	9,235
$/boe	**4.45**	5.52	**4.29**	5.87

Total production and operating expenses were down 19% on a unit-of-production basis to $4.45/boe for the second quarter of 2018, compared to $5.52/boe for the comparable period of 2017. On an absolute dollar basis, production and operating costs were down by $0.3 million, despite the 15% increase in production. Increased production at East Edson combined with a low variable cost structure, drove West Central operating costs down to $2.25/boe in the second quarter of 2018 (Q2 2017 – $3.29/boe). The first quarter of 2018 saw higher than average well servicing requirements in the Mannville heavy oil operations which increased Eastern Alberta operating costs compared to the prior year period, while negatively affecting production volumes.

Transportation costs

($ thousands, except as noted)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Transportation costs	**1,546**	1,226	**2,989**	2,241
$/boe	**1.60**	1.46	**1.41**	1.43

Transportation costs include clean oil trucking and NGL transportation as well as costs to transport natural gas from the plant gate to commercial sales points. Transportation costs in the second quarter of 2018 were $1.5 million, up 26% from the prior year period due to the increase in firm transportation commitments at East Edson that commenced in December 2017. Transportation costs averaged $1.50/boe at West Central compared to $2.07/boe for production from Eastern Alberta. On a unit-of-production basis, transportation costs were $1.60/boe in the second quarter, up 10% from the prior year period due to the nature of fixed firm capacity transportation costs against lower production. During the second quarter of 2018, the Company was not able to mitigate any of its excess firm transportation costs.

Gas over bitumen

($ thousands, except as noted)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Gas over bitumen royalty credit	**170**	687	**553**	1,612
Payments on gas over bitumen royalty financing[(1)]	**(260)**	(710)	**(699)**	(1,526)
Gas over bitumen, net of payments	**(90)**	(23)	**(146)**	86
$/boe	**(0.09)**	(0.03)	**(0.07)**	0.05

(1) At June 30, 2018, the fair value of the gas over bitumen royalty financing was estimated to be $2.1 million (December 31, 2017 – $2.7 million).

Perpetual records revenue in relation to gas over bitumen royalty credits received under the Natural Gas Royalty Regulation for natural gas wells which have been shut-in pursuant to shut-in orders issued by the Government of Alberta. During the second quarter of 2018, Perpetual recorded $0.2 million in gas over bitumen revenue, a 75% decrease from $0.7 million in the same period of 2017. The decrease in gas over bitumen revenue is attributable to the 62% decline in Alberta gas reference prices, combined with the annual 10% decline in deemed production.

Gas over bitumen royalty credits earned in the second quarter of 2018 funded payments of $0.3 million (Q2 2017 – $0.7 million) in relation to the 2014 monetization of Perpetual's future gas over bitumen royalty credits. As part of the arrangement, Perpetual makes monthly payments to the purchaser, which from time to time will vary from the actual gas over bitumen royalty credit received in the period due to timing differences. The monthly payment commitment expires concurrent with the gas over bitumen royalty credit, with final expiries expected to occur in June 2021.

Under IFRS, the monetization of future gas over bitumen royalty credits was recorded as a financial obligation ("Gas over bitumen royalty financing"); however, entitlement to future revenue from gas over bitumen royalty adjustments are not recorded as an asset but as revenue with the passage of time as it is earned. As such, gas over bitumen revenue will continue to be recognized separately as revenue in accordance with Perpetual's accounting policies with the monthly payments recognized as a reduction to the gas over bitumen royalty financing obligation. For purposes of this MD&A, the monthly payments have been included as a reduction to gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty adjustments. During the second quarter of 2018, the gas over bitumen royalty financing obligation was reduced by $0.1 million, comprised of payments of $0.3 million and an unrealized loss of $0.2. The loss has been included in non-cash finance expense and represents an increase in the fair value of the gas over bitumen royalty financing obligation as a result of higher forecasted natural gas reference prices.

Exploration and evaluation

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Lease rentals	**172**	181	**342**	369
Geological and geophysical costs	**–**	(22)	**–**	(22)
Lease expiries (non-cash)	**–**	505	**–**	1,818
Total exploration and evaluation	**172**	664	**342**	2,165

Exploration and evaluation ("E&E") costs include lease rentals on undeveloped acreage, geological and geophysical costs and the write-down of carrying costs related to lease expiries. Comparable with the prior year period, Perpetual recorded E&E costs of $0.2 million for the three months ended June 30, 2018, comprised entirely of lease rentals.

General and administrative ("G&A") expenses

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Cash G&A expense	**3,475**	3,553	**7,389**	7,758
Overhead recoveries	**(345)**	(411)	**(948)**	(1,515)
Total G&A expense	**3,130**	3,142	**6,441**	6,243
$/boe	**3.24**	3.74	**3.05**	3.97

During the second quarter of 2018, cash G&A expense was $3.5 million, a modest decrease from the prior year period of $3.6 million. Compared to the prior year period, overhead recoveries decreased by 16% as a result of reduced capital spending, offset partially by the increase in expenditures on decommissioning obligations. On a unit-of-production basis, total G&A expense of $3.24/boe for the three months and $3.05/boe for the six months ended June 30, 2018, was down 13% and 23% respectively from the prior year periods due to increasing production.

Share-based payments

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Share-based payments expense (non-cash)	**693**	985	**1,499**	2,517
$/boe	**0.72**	1.17	**0.71**	1.60

Non-cash share-based payments expense for the three months ended June 30, 2018 was $0.7 million, down 30% compared to the same period in 2017 due to a reduction in the value of outstanding share-based payment awards.

Depletion and depreciation

	Three months ended June 30,		Six months ended June 30,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Depletion and depreciation	**8,783**	7,929	**18,907**	15,054
$/boe	**9.09**	9.45	**8.95**	9.58

Perpetual recorded $8.8 million of depletion and depreciation expense for the three months ended June 30, 2018, an increase of 11% over $7.9 million recorded in the prior year period. The increase reflects the 15% growth in production volumes compared to the prior year period, partially offset by a 4% reduction in the depletion rate following the success of the Company's 2017 capital expenditure program that added proved plus probable reserves at a cost of $5.98/boe in 2017.

Finance expenses

($ thousands)	Three months ended June 30, 2018	2017	Six months ended June 30, 2018	2017
Cash interest expense and income				
Interest on revolving bank debt	**504**	204	**972**	384
Interest on TOU share margin loan	**162**	87	**310**	301
Interest on term loan	**907**	709	**1,818**	854
Interest on senior notes	**722**	921	**1,443**	2,279
Dividend income from TOU share investment	**(152)**	–	**(285)**	–
Total cash interest expense and income	**2,143**	1,921	**4,258**	3,818
Non-cash finance expense				
Amortization of debt issue costs	**267**	189	**517**	283
Accretion on decommissioning obligations	**208**	195	**415**	386
Change in fair value of gas over bitumen royalty financing	**198**	33	**68**	(1,206)
Change in fair value of TOU share put option margin loans	**–**	504	**–**	1,425
Total non-cash finance expense	**673**	921	**1,000**	888
Finance expenses recognized in net loss	**2,816**	2,842	**5,258**	4,706

Total cash interest expense and income of $2.1 million for the three months ended June 30, 2018 was 12% higher than the prior year period (Q2 2017 – $1.9 million) due to increased debt levels compared to the prior year period, partially offset by dividend income of $0.2 million ($0.09 per TOU share) received from the TOU share investment during the second quarter of 2018.

Total non-cash finance expense for the three months ended June 30, 2018 was $0.7 million (Q2 2017 – $0.9 million). An increase in the fair value of the gas over bitumen royalty financing was recorded in both periods due to higher AECO future natural gas prices, resulting in a fair value at June 30, 2018 of $2.1 million. The $0.5 million change in the fair value of TOU share put option margin loans recorded in the second quarter of 2017 did not re-occur in the second quarter of 2018 as these loans were refinanced during the third quarter of 2017 without embedded put option derivatives.

Change in fair value of TOU share investment

During the three months ended June 30, 2018, Perpetual recorded a gain of $2.8 million related to the change in fair value of the TOU share investment. This change was due to an 8% increase in the TOU share price over the second quarter. For the six months ended June 30, 2018, Perpetual recorded a gain of $1.2 million due to the 3% increase in the TOU share price during the period. At June 30, 2018, the Company owned 1.66 million TOU shares (December 31, 2017 – 1.67 million shares) having a quoted market value of $38.9 million (December 31, 2017 – $38.0 million).

LIQUIDITY AND CAPITAL RESOURCES

Perpetual's strategy includes maintaining a strong capital base to retain investor, creditor and market confidence to support the execution of its business plans. The Company manages its capital structure and adjusts its capital spending in light of changes in economic conditions 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 loan and net working capital, with value and liquidity enhanced through the current ownership of TOU shares. To manage its capital structure and available liquidity, the Company may from time to time issue equity or debt securities, sell its TOU shares or other assets and adjust its capital spending to manage current and projected debt levels. The Company will continue to regularly assess changes to its capital structure and repayment alternatives, with considerations for both short term liquidity and longer term financial sustainability.

Capital management

(*$ thousands, except as noted*)	**June 30, 2018**	December 31, 2017
Revolving bank debt	**42,752**	31,581
Term loan, measured at principal amount	**45,000**	45,000
TOU share margin loan, measured at principal amount	**15,714**	18,490
Senior notes, measured at principal amount	**32,490**	32,490
TOU share investment(1)	**(38,917)**	(37,985)
Net working capital deficiency(2)	**3,123**	16,404
Net debt(2)	**100,162**	105,980
Shares outstanding at end of period (*thousands*)(3)	**60,369**	59,263
Market price at end of period (*$/share*)	**0.65**	1.10
Market value of shares	**39,240**	65,189
Enterprise value(2)	**139,402**	171,169
Net debt as a percentage of enterprise value	**72**	62
Trailing twelve months adjusted funds flow(2)	**37,688**	31,115
Net debt to trailing twelve months adjusted funds flow	**2.7 times**	3.4 times

(1) The TOU share investment is based on the June 30, 2018 closing price per the Toronto Stock Exchange ($23.49 per share) and 1.66 million TOU shares held (December 31, 2017 – 1.67 million TOU shares held with a closing price of $22.78 per share).
(2) See "Non-GAAP measures" in this MD&A.
(3) Shares outstanding are presented net of shares held in trust.

At June 30, 2018, Perpetual had total net debt of $100.2 million, down $5.8 million from December 31, 2017 and $14.9 million from March 31, 2018 as net cash flow from operations, net proceeds from non-core asset sales completed in the second quarter, and the increased market value of the TOU share investment, exceeded capital expenditures during the second quarter and on a year-to-date basis. The net working capital deficiency of $3.1 million at June 30, 2018 decreased by $13.3 million from December 31, 2017, due to the seasonal reduction in capital expenditures during the second quarter when break up conditions in Alberta reduce access for field activities. The decrease in the net working capital deficiency was offset by a corresponding increase in revolving bank debt.

As at June 30, 2018, 63% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow improved slightly during the six months ended June 30, 2018 to 2.7 times at June 30, 2018 (December 31, 2017 – 3.4 times). At June 30, 2018, Perpetual had available liquidity of $36.7 million.

TOU share margin loan

At June 30, 2018, Perpetual had a $15.7 million TOU share margin loan ($15.7 million principal amount) secured by 1.66 million TOU shares that matures on July 31, 2018. 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 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%.

During the quarter ended June 30, 2018, Perpetual sold 10,700 TOU shares at $25.97 per share and used the proceeds of $0.3 million to partially repay the TOU share margin loan. As at June 30, 2018, the Lending Ratio was 40% of the closing market value of the pledged TOU shares. The TOU share margin loan is designated as a financial liability for accounting purposes and measured at amortized cost.

The effective interest rate on the TOU share margin loan as at June 30, 2018 was 4.1%. For the period ended June 30, 2018, if interest rates changed by 1%, with all other variables held constant, the impact on annual interest expense and net income (loss) would be $0.2 million.

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 as at June 30, 2018.

On July 31, 2018, the TOU share margin loan was converted into a demand loan with the same lender, with similar terms and conditions. Interest rates are based on Banker's Acceptance rates plus 1.25%.

Revolving bank debt

As at June 30, 2018, the Company's reserve-based revolving credit facility (the "Credit Facility") had a borrowing limit (the "Borrowing Limit") of $60 million (December 31, 2017 – $65.0 million) under which $42.8 million was drawn (December 31, 2017 – $31.6 million) and $3.7 million of letters of credit had been issued (December 31, 2017 – $3.9 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%.

On May 7, 2018, the Borrowing Limit was reduced from $65.0 million to $60.0 million, with the next Borrowing Limit redetermination scheduled on or prior to November 30, 2018. If not extended, the Credit Facility will cease to revolve, and all outstanding advances will be repayable on May 31, 2019. As the Credit Facility now matures in less than one year, it has been presented as a current liability on the condensed interim consolidated statement of financial position as at June 30, 2018. On May 9, 2018 and on May 24, 2018, Moody's Investors Service and S&P Global ratings reduced their corporate credit rating by one notch to Caa2 and CCC respectively, with negative outlooks based on the current maturity of its revolving bank debt (if not extended) and the pending maturity of $14.6 million senior notes in July 2019.

The Credit Facility is secured by general security agreements covering all of the Company's assets, with the exception of the TOU shares that have been pledged as security for the TOU share margin loan and certain lands pledged to the gas over bitumen royalty financing counterparty. The Credit Facility also contains provisions which restrict the Company's ability to pay dividends on or repurchase its common shares.

The effective interest rate on the Credit Facility at June 30, 2018 was 4.6%. For the period ended June 30, 2018, if interest rates changed by 1% with all other variables held constant, the impact on annual interest expense and net income (loss) would be $0.4 million (Q2 2017 – nil).

At June 30, 2018, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Term loan

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

($ thousands)	**June 30, 2018**	December 31, 2017
Balance, beginning of period	**$ 43,233**	$ –
Principal amount of term loan issued	**–**	45,000
Value allocated to warrants issued	**–**	(769)
Issue costs	**–**	(1,361)
Amortization of issue costs	**243**	363
Balance, end of period	**$ 43,476**	$ 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. 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 June 30, 2018, the term loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

			June 30, 2018		December 31, 2017	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 senior notes	July 23, 2019	8.75%	**14,572**	**14,506**	14,572	14,476
2022 senior notes	January 23, 2022	8.75%(1)	**17,918**	**17,266**	17,918	17,204
			$ 32,490	**$ 31,772**	$ 32,490	$ 31,680

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

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

The senior notes are direct senior unsecured obligations of the Company, ranking pari passu with all other present and future unsecured and unsubordinated indebtedness of the Company. At any time prior to three years before the senior note maturity date, the Company can redeem up to 35 percent of the principal amount of the senior notes at a premium to face value. Within three years of maturity, the Company may redeem up to 100 percent of the senior notes at a premium to face value. Within one year of maturity, the Company may redeem up to 100 percent of the senior notes at the principal amount.

The senior notes have a cross-default provision with the Company’s Credit Facility. In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt and stock repurchases. The permitted amount of any restricted payment is limited to:

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

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

At June 30, 2018 the senior notes are presented net of $0.7 million in issue costs which are amortized using a weighted average effective interest rate of 9.6%.

At June 30, 2018, other than the restricted payment covenants noted above, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Equity

At June 30, 2018 there were 60.4 million common shares outstanding, net of 0.4 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended June 30, 2018 were 59.9 million (Q2 2017 – 59.0 million) and 59.6 million for the six months ended June 30, 2018 (2017 – 56.8 million).

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

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

At August 2, 2018 there were 60.4 million common shares outstanding which is net of 0.5 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)	**August 2, 2018**
Share options(1)	**3.9**
Performance share rights(2)	**1.5**
Compensation awards(3)	**3.3**
Warrants(4)	**6.5**
Total	**15.2**

(1) As at June 30, 2018, all outstanding share options have an exercise price that is greater than the closing price of the Company's common shares of $0.65 per share. Therefore, the actual number of potentially issuable common shares would be nil.
(2) The performance share rights that vest and become redeemable are a multiple of the performance share rights granted, dependent upon the achievement of certain performance metrics over the vesting period. As at June 30, 2018, performance multipliers of 1.0 have been assumed for those unvested awards granted in 2017 and 2018.
(3) As at June 30, 2018, 2.0 million deferred options have an exercise price that is greater than the closing price of the Company's common shares of $0.65 per share. Therefore, the actual number of potentially issuable common shares pursuant to the compensation awards would be 1.3 million.
(4) As at June 30, 2018, all outstanding warrants have an exercise price that is greater than the closing price of the Company's common shares of $0.65 per share. Therefore, the actual number of potentially issuable common shares would be nil.

SUMMARY OF QUARTERLY RESULTS

(*$ thousands, except as noted*)	**Q2 2018**	Q1 2018	Q4 2017	Q3 2017
Financial				
Oil and natural gas revenue	**20,774**	23,340	23,810	20,026
Net loss	**(1,325)**	(6,465)	(6,498)	(8,082)
Per share – basic and diluted	**(0.02)**	(0.11)	(0.11)	(0.14)
Cash flow from (used in) operating activities	**8,435**	11,198	10,953	5,778
Adjusted funds flow(1)	**7,847**	9,101	12,541	8,199
Per share – basic	**0.13**	0.15	0.21	0.14
Net capital expenditures				
Capital expenditures	**2,031**	14,897	19,047	25,392
Net payments (proceeds) on acquisitions and dispositions	**(7,012)**	926	970	680
Net capital expenditures	**(4,981)**	15,823	20,017	26,072
Common shares (*thousands*)				
Weighted average – basic	**59,876**	59,345	59,338	59,152
Weighted average – diluted	**59,876**	59,345	59,338	59,152
Operating				
Daily average production				
Natural gas (*MMcf/d*)	**53.1**	65.9	60.8	51.8
Oil (*bbl/d*)	**971**	900	888	978
NGL (*bbl/d*)	**806**	848	738	733
Total (*boe/d*)	**10,620**	12,742	11,765	10,330
Average prices				
Realized natural gas price (*$/Mcf*)(2)	**2.62**	2.65	3.22	3.11
Realized oil price (*$/bbl*)(2)	**53.26**	48.31	47.30	43.01
NGL price (*$/bbl*)	**60.77**	57.61	54.17	39.06

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

(*$ thousands, except as noted*)	Q2 2017	Q1 2017	Q4 2016	Q3 2016
Financial				
Oil and natural gas revenues	19,728	18,158	17,940	22,268
Net income (loss)	(7,219)	(14,172)	20,379	(10,919)
Per share – basic	(0.12)	(0.26)	0.39	(0.21)
Per share – diluted	(0.12)	(0.26)	0.37	(0.21)
Cash flow from (used in) operating activities	4,728	(2,289)	4,740	(1,710)
Adjusted funds flow[1]	5,265	5,110	3,329	(602)
Per share – basic	0.09	0.09	0.06	(0.01)
Net capital expenditures				
Exploration and development and other	4,006	24,590	7,069	1,411
Net payments (proceeds) on acquisitions and dispositions	609	163	1,785	(988)
Net capital expenditures	4,615	24,753	8,854	423
Common shares (*thousands*)				
Weighted average – basic	59,045	54,468	52,924	52,253
Weighted average – diluted	59,045	54,468	54,678	52,253
Operating				
Daily average production				
Natural gas (*MMcf/d*)	45.1	40.7	40.3	75.5
Oil (*bbl/d*)	1,049	877	936	1,052
NGL (*bbl/d*)	665	479	467	476
Total (*boe/d*)	9,223	8,143	8,118	14,123
Average prices				
Realized natural gas price (*$/Mcf*)	3.18	5.04	2.41	2.12
Realized oil price (*$/bbl*)	43.91	31.39	38.95	38.90
NGL price (*$/bbl*)	44.28	49.70	46.99	35.80

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

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 decreased 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 Disposition. Production levels increased through 2017 as net capital expenditures were increased in response to improving commodity prices. Capital expenditures are typically low during the second quarter when break-up conditions in Alberta reduce access for field activities.

Commodity price risk management and sales obligations

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

The following tables provide a summary of commodity price risk management contracts outstanding at August 2, 2018:

Natural Gas

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

Term	**Volumes sold (bought) at AECO (*GJ/d*)**	**Average price (*$/GJ*)[1]**	**Market prices (*$/GJ*)[2]**	**Type of contract**
July 2018 – October 2018	10,000	2.06	1.45	Financial
July 2018 – March 2019	10,000	1.41	1.72	Financial
September 2018 – March 2019	5,000	1.40	1.81	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for July and August 2018 are based on settled AECO Monthly Index prices. Market prices for subsequent months are based on forward AECO Monthly Index prices as of market close on August 2, 2018.

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

Term	**Volumes sold (bought)** ***(MMBtu/d)***	**AECO-NYMEX differential** ***(US$/MMBtu)***[(1)]	**Market prices** ***(US$/MMBtu)***[(2)]	**Type of contract**
July 2018	(10,000)	(2.00)	(1.88)	Financial
July 2018 – October 2018	5,000	(1.87)	(1.70)	Financial
July 2018 – October 2018	7,500	(1.80)	(1.70)	Physical
July 2018 – October 2018	(7,500)	(1.92)	(1.70)	Physical
August 2018	(25,000)	(1.86)	(1.74)	Physical
September 2018	(5,000)	(1.82)	(1.66)	Physical
October 2018	(2,500)	(1.63)	(1.53)	Physical
November 2018 – March 2019	7,500	(1.55)	(1.38)	Physical
January 2019 – December 2019	12,500	(1.54)	(1.40)	Physical
January 2019 – December 2019	7,500	(1.50)	(1.40)	Financial
January 2020 – December 2020	12,500	(1.41)	(1.32)	Physical
January 2020 – December 2020	15,000	(1.41)	(1.32)	Financial
January 2021 – December 2021	5,000	(1.15)	(1.23)	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for July and August 2018 are based on settled AECO-NYMEX differential prices. Market prices for subsequent months are based on forward AECO-NYMEX differential prices as of market close on August 2, 2018.

Crude Oil

The following table provides a summary of fixed price oil contracts which settle in US$:

Term	**Volumes** ***(bbl/d)***	**Fixed price** ***(US$/bbl)***[(1)]	**Market prices** ***(US$/bbl)***[(2)]	**Type of contract**
July 2018 – December 2018	250	63.74	67.75	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for July are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on August 2, 2018.

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

Term	**Volumes** ***(bbl/d)***	**Floor price** ***(US$/bbl)***	**Ceiling price** ***(US$/bbl)***	**Market prices** ***(US$/bbl)***[(1)]	**Type of contract**
July 2018 – December 2018	250	50.00	58.40	67.75	Financial
July 2018 – December 2018	250	50.00	60.00	67.75	Financial

(1) Market prices for July are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on August 2, 2018.

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**
July 2018	500	(19.75)	(17.75)	Financial

(1) Average price calculated using weighted average price for net open contracts; contracts settle at WTI index less a fixed basis amount.
(2) Market prices for July are based on settled WTI-WCS differential prices. Market prices for subsequent months are based on forward WTI-WCS differential prices as of market close on August 2, 2018.

Foreign Exchange

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

Term	**Notional** ***(US$/month)***	**Strike rate** ***(US$/Cdn$)***	**Market prices** ***(US$/Cdn$)***
July 2018 – October 2018	1,500,000	1.30	1.30

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

Term	**Notional** ***(US$/month)***	**Strike rate** ***(US$/Cdn$)***	**Market prices** ***(US$/Cdn$)***
July 2018 – October 2018	2,000,000	1.30	1.30
November 2018 – March 2019	1,500,000	1.30	1.30
April 2019 – October 2019	1,000,000	1.32	1.30

Natural Gas Sales Obligations

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

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

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

ACCOUNTING PRONOUNCEMENTS

Recently adopted

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

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

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

Issued but not yet adopted

IFRS 16 "Leases"
Perpetual is required to adopt IFRS 16 "Leases" by January 1, 2019. IFRS 16 requires lessees to recognize a lease obligation and right-of-use asset for the majority of leases. On adoption, non-current assets, current liabilities and non-current liabilities on the Company's statement of financial position will increase. Interest expense will be recognized on the lease obligation and lease payments will be applied against the lease obligation. This is expected to result in a decrease to operating expense and general and administrative expense and an increase to interest expense and adjusted funds flow. The Company will disclose additional information throughout the latter half of 2018 on the progress of the transition and has yet to quantify the impacts of this standard.

CORPORATE GOVERNANCE

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

INTERNAL CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures

There were no changes in the Corporation's internal control over financial reporting during the period beginning on January 1, 2018 and ended June 30, 2018 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

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

In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the quantity and recoverability of Perpetual's reserves; the timing and amount of future production; future prices as well as supply and demand for natural gas, NGLs 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 and term loan covenants in 2018 and 2019; the retention of, and benefits to be received from holding the TOU share investment; expected book value and related tax value of the Corporation's assets and prospect inventory and estimates of net asset value; adjusted funds flow; ability to fund exploration and development; the corporate strategy; expectations regarding Perpetual's access to capital to fund its acquisition, exploration and development activities; the effect of future accounting pronouncements and their impact on the Corporation's financial results; future income tax and its effect on adjusted funds flow; intentions with respect to preservation of tax pools and taxes payable by the Corporation; funding of and anticipated results from capital expenditure programs; renewal of and borrowing costs associated with the credit facility; future debt levels, financial capacity, liquidity and capital resources; future contractual commitments; drilling, completion, facilities, construction and waterflood plans, and the effect thereof; the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other issuers; Crown royalty rates; Perpetual's treatment under governmental regulatory regimes; business strategies and plans of management including future changes in the structure of business operations and debt reduction initiatives; and the reliance on third parties in the industry to develop and expand Perpetual's assets and operations.

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

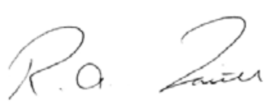
The Corporation believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable, but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements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

PERPETUAL ENERGY INC.
Condensed Interim Consolidated Statements of Financial Position

As at	June 30, 2018	December 31, 2017
(*Cdn$ thousands unaudited*)		
Assets		
Current assets		
Accounts receivable (note 14)	**$ 7,745**	$ 14,069
Tourmaline Oil Corp. ("TOU") share investment (note 3)	**38,917**	37,985
Prepaid expenses and deposits	**874**	937
Fair value of derivatives (note 16)	**185**	1,585
	47,721	54,576
Fair value of derivatives (note 16)	**132**	1,506
Property, plant and equipment (note 4)	**260,134**	262,784
Exploration and evaluation (note 5)	**36,569**	46,704
Total assets	**$ 344,556**	$ 365,570
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 11,742**	$ 31,410
Fair value of derivatives (note 16)	**5,489**	7,885
TOU share margin loan (note 7)	**15,699**	18,406
Revolving bank debt (note 8)	**42,752**	–
Gas over bitumen royalty financing	**1,114**	1,152
Provisions (note 11)	**2,002**	2,580
	78,798	61,433
Fair value of derivatives (note 16)	**144**	–
Revolving bank debt (note 8)	**–**	31,581
Term loan (note 9)	**43,476**	43,233
Senior notes (note 10)	**31,772**	31,680
Gas over bitumen royalty financing	**994**	1,587
Provisions (note 11)	**35,956**	36,105
Total liabilities	**191,140**	205,619
Equity		
Share capital (note 12)	**1,338,256**	1,336,838
Warrants (note 12c)	**923**	923
Contributed surplus	**43,989**	44,152
Deficit	**(1,229,752)**	(1,221,962)
Total equity	**153,416**	159,951
Total liabilities and equity	**$ 344,556**	$ 365,570

See accompanying notes to the condensed interim consolidated financial statements.



Robert A. Maitland
Director

Geoffrey C. Merritt
Director

PERPETUAL ENERGY INC.
Condensed Interim Consolidated Statements of Loss and Comprehensive Loss

(*Cdn$ thousands, except per share amounts, unaudited*)	Three months ended June 30, **2018**	Three months ended June 30, 2017	Six months ended June 30, **2018**	Six months ended June 30, 2017
Revenue				
Oil and natural gas (note 14)	**$ 20,774**	$ 19,728	**$ 44,114**	$ 37,886
Royalties	**(2,590)**	(3,606)	**(5,653)**	(6,708)
	18,184	16,122	**38,461**	31,178
Change in fair value of derivatives (note 16)	**(1,730)**	1,291	**(3,365)**	5,284
Gas over bitumen royalty credit and other	**170**	773	**553**	1,698
	16,624	18,186	**35,649**	38,160
Expenses				
Production and operating	**4,304**	4,634	**9,076**	9,235
Transportation	**1,546**	1,226	**2,989**	2,241
Exploration and evaluation (note 5)	**172**	664	**342**	2,165
General and administrative	**3,130**	3,142	**6,441**	6,243
Share-based payments (note 13)	**693**	985	**1,499**	2,517
Depletion and depreciation (note 4)	**8,783**	7,929	**18,907**	15,054
Loss (gain) on dispositions (note 4a)	**(734)**	1,032	**137**	3,223
Loss from operating activities	**(1,270)**	(1,426)	**(3,742)**	(2,518)
Finance expense (note 15)	**(2,816)**	(2,842)	**(5,258)**	(4,706)
Change in fair value of TOU share investment (note 3)	**2,761**	(2,951)	**1,210**	(14,167)
Net loss and comprehensive loss	**(1,325)**	(7,219)	**(7,790)**	(21,391)
Net loss per share (note 12d)				
Basic and diluted	**$ (0.02)**	$ (0.12)	**$ (0.13)**	$ (0.38)

See accompanying notes to the condensed interim consolidated financial statements.

PERPETUAL ENERGY INC.
Condensed Interim Consolidated Statements of Changes in Equity

	Share capital *(thousands)*	Share capital *($thousands)*	Warrants	Contributed surplus	Deficit	Total equity
(Cdn$ thousands unaudited)						
Balance at December 31, 2017	59,263	$ 1,336,838	$ 923	$ 44,152	$ (1,221,962)	$ 159,951
Net loss	–	–	–	–	(7,790)	(7,790)
Common shares issued (note 12)	1,126	1,154	–	(1,148)	–	6
Change in shares held in trust	(20)	264	–	(514)	–	(250)
Share-based payments	–	–	–	1,499	–	1,499
Balance at June 30, 2018	**60,369**	**$1,338,256**	**$ 923**	**$ 43,989**	**$(1,229,752)**	**$ 153,416**

	Share capital *(thousands)*	Share capital *($thousands)*	Warrants	Contributed surplus	Deficit	Total equity
(Cdn$ thousands unaudited)						
Balance at December 31, 2016	53,421	$ 1,325,705	$ –	$ 42,999	$ (1,185,991)	$ 182,713
Net loss	–	–	–	–	(21,391)	(21,391)
Common shares and warrants issued (note 12)	5,861	10,384	923	(1,811)	–	9,496
Change in shares held in trust	(247)	(261)	–	–	–	(261)
Share-based payments	–	–	–	2,517	–	2,517
Balance at June 30, 2017	**59,035**	**$1,335,828**	**$ 923**	**$ 43,705**	**$(1,207,382)**	**$ 173,074**

See accompanying notes to the condensed interim consolidated financial statements.

PERPETUAL ENERGY INC.
Condensed Interim Consolidated Statements of Cash Flows

	Three months ended June 30, **2018**	Three months ended June 30, 2017	Six months ended June 30, **2018**	Six months ended June 30, 2017
(*Cdn$ thousands, unaudited*)				
Cash flows from (used in) operating activities				
Net loss	**$ (1,325)**	$ (7,219)	**$ (7,790)**	$ (21,391)
Adjustments to add (deduct) non-cash items:				
Depletion and depreciation (note 4)	**8,783**	7,929	**18,907**	15,054
Exploration and evaluation (note 5)	**–**	505	**–**	1,818
Share-based payments (note 13)	**693**	985	**1,499**	2,517
Change in fair value of derivatives (note 16)	**2,778**	(1,129)	**5,104**	(4,375)
Change in fair value of TOU share investment (note 3)	**(2,761)**	2,951	**(1,210)**	14,167
Loss (gain) on dispositions (note 4a)	**(734)**	1,032	**137**	3,223
Finance expenses (note 15)	**673**	921	**1,000**	888
Expenditures on decommissioning obligations (note 11a)	**(353)**	26	**(906)**	(537)
Payments of restructuring costs (note 11b)	**(50)**	(555)	**(235)**	(1,899)
Change in non-cash working capital	**731**	(718)	**3,127**	(7,026)
Net cash from operating activities	**8,435**	4,728	**19,633**	2,439
Cash flows from (used in) financing activities				
Change in revolving bank debt, net of issue costs	**(4,205)**	4,404	**11,081**	4,404
Change in term loan, net of issue costs	**–**	21	**–**	33,749
Change in TOU share margin loan, net of issue costs	**(276)**	–	**(2,799)**	(5,835)
Change in senior notes, net of issue costs	**–**	(27,170)	**–**	(27,514)
Change in gas over bitumen royalty financing	**(260)**	(710)	**(699)**	(1,526)
Common shares and warrants issued	**6**	87	**6**	9,032
Shares purchased and held in trust (note 12)	**(250)**	(566)	**(250)**	(566)
Change in non-cash working capital	**–**	–	**–**	(216)
Net cash from (used in) financing activities	**(4,985)**	(23,934)	**7,339**	11,528
Cash flows from (used in) investing activities				
Capital expenditures	**(2,031)**	(4,006)	**(16,928)**	(28,596)
Acquisitions	**(610)**	–	**(610)**	(208)
Net proceeds (payments) on dispositions (note 4a)	**7,622**	(609)	**6,696**	(564)
Proceeds on sale of TOU share investment (note 3)	**278**	–	**278**	5,687
Restricted cash	**–**	–	**–**	2,000
Change in non-cash working capital	**(8,709)**	(14,410)	**(16,408)**	4,837
Net cash used in investing activities	**(3,450)**	(19,025)	**(26,972)**	(16,844)
Change in cash and cash equivalents	**–**	(38,231)	**–**	(2,877)
Cash and cash equivalents, beginning of period	**–**	38,231	**–**	2,877
Cash and cash equivalents, end of period	**$ –**	$ –	**$ –**	$ –

See accompanying notes to the condensed interim consolidated financial statements.

1. REPORTING ENTITY

Perpetual Energy Inc. ("Perpetual" or the "Company") is a Canadian corporation engaged in the exploration, development and marketing of oil and natural gas based energy in Alberta, Canada. The Company operates a diversified asset portfolio that includes liquids-rich natural gas, shallow natural gas and conventional heavy oil producing properties, as well as undeveloped bitumen resource properties.

The address of the Company's registered office is 3200, 605 – 5 Avenue S.W., Calgary, Alberta, T2P 3H5.

The condensed interim consolidated financial statements of the Company as at and for the three and six months ended June 30, 2018 are comprised of the accounts of Perpetual Energy Inc. and its wholly owned subsidiaries: Perpetual Operating Corp. and Perpetual Operating Trust, which are incorporated in Canada.

2. BASIS OF PREPARATION

These condensed interim consolidated financial statements have been prepared in accordance with IAS 34 Interim Financial Reporting and do not include all of the information required for full annual financial statements. These condensed interim consolidated financial statements should be read in conjunction with the Company's consolidated financial statements as at and for the year ended December 31, 2017 which were prepared in conformity with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Except for the changes described below, the accounting policies, basis of measurement, critical accounting judgements and significant estimates used to prepare the annual consolidated financial statements as at and for the year ended December 31, 2017 have been applied in the preparation of these condensed interim consolidated financial statements.

These condensed interim consolidated financial statements of the Corporation were approved and authorized for issue by the Board of Directors on August 2, 2018.

a) Accounting pronouncements adopted

IFRS 9 "Financial Instruments"

Effective January 1, 2018, the Company adopted IFRS 9, "Financial Instruments", which replaced IAS 39, "Financial Instruments: Recognition and Measurement". The Company applied the new standard retrospectively and, in accordance with the transitional provisions, comparative figures have not been restated. The adoption of IFRS 9 did not have a material impact on the Company's condensed interim consolidated financial statements.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income ("FVOCI") and fair value through profit or loss ("FVTPL"). The previous IAS 39 categories of held to maturity, loans and receivables, and available for sale have been eliminated. The classification of financial assets under IFRS 9 is generally based on the contractual cash flow characteristics and the Company's business model for managing the financial asset. Additionally, embedded derivatives are not separated if the host contract is a financial asset within the scope of IFRS 9. Instead, the entire hybrid contract is assessed for classification and measurement.

A financial asset is measured at amortized cost if it meets both of the following conditions and is not designated as FVTPL:

i) The asset is held with the objective to collect contractual cash flows; and
ii) The contractual terms of the financial asset give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

Financial assets that meet condition (ii) above that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets is subsequently measured at FVOCI. All other financial assets are subsequently measured at their fair values with changes in fair value recognized through profit and loss.

IFRS 9 replaces the 'incurred loss' model in IAS 39 with an 'expected credit loss' ("ECL") model. The new impairment model applies to financial assets measured at amortized cost, contract assets, and debt investments measured at FVOCI. Under IFRS 9, credit losses will be recognized earlier than under IAS 39.

The ECL model applies to the Company's receivables. The average expected credit loss on the Company's trade accounts receivable was not significant as at June 30, 2018.

On January 1, 2018, the Company:

- Identified the business model used to manage its financial assets and classified its financial instruments into the appropriate IFRS 9 category; and
- Applied the ECL model to financial assets measured at amortized cost.

The classification and measurement of financial instruments under IFRS 9 did not result in any adjustment to the Company's opening retained earnings as at January 1, 2018. In addition, the application of the ECL model to financial assets classified as measured at amortized cost did not result in any adjustment on transition.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of the Company's financial assets and financial liabilities. The Company has no contract assets or debt investments measured at FVOCI.

	Measurement Category	
Financial Instrument	**IAS 39**	**IFRS 9**
Accounts receivable	Loans and receivables at amortized cost	Amortized cost
TOU share investment	Financial assets at FVTPL	FVTPL
Accounts payable and accrued liabilities	Financial liabilities at amortized cost	Amortized cost
TOU share margin loan	Financial liabilities at amortized cost	Amortized cost
Revolving bank debt	Financial liabilities at amortized cost	Amortized cost
Term loan	Financial liabilities at amortized cost	Amortized cost
Senior notes	Financial liabilities at amortized cost	Amortized cost
Gas over bitumen royalty financing	Financial liabilities at FVTPL	FVTPL

In addition, IFRS 9 provides a hedge accounting model that is more in line with risk management activities. The Company does not currently apply hedge accounting to its derivative contracts nor does it intend to apply hedge accounting under IFRS 9 and as such, derivatives will continue to be FVTPL. In addition, the Company will continue to account for its forward physical delivery fixed-price sales contracts as derivative financial instruments.

IFRS 15 "Revenue from Contracts with Customers"

The Company adopted IFRS 15 "Revenue from Contracts with Customers" with a date of initial application of January 1, 2018 as detailed in Note 14, using the cumulative effect method. Under this method, prior years financial statements have not been restated and the cumulative effect on net loss of the application of IFRS 15 to revenue contracts in progress at January 1, 2018 is nil. The Company's management reviewed its revenue streams and major contracts with customers using the IFRS 15 five step model and there were no material changes to net loss or timing of oil and natural gas revenue recognized.

Under IFRS 15, revenue from the sale of commodities is calculated by reference to consideration specified in contracts with customers and recognized when control of the product is transferred to the buyer. The nature of each of its performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal, and therefore recognizes revenue on a gross basis, or as an agent, and therefore recognizes revenue on a net basis. The Company acts as the principal when it controls the product delivered before the control passes to its customer.

The Company earns revenue from its production and sale of, and royalty (and gross overriding royalty) interests in, crude oil, natural gas and natural gas liquids ("NGL's").

Revenue from the sale of crude oil, natural gas and NGLs is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when control of the product transfers to the buyer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipelines or other transportation method agreed upon. Revenues from processing activities are recognized over time as processing occurs and are generally billed monthly. Royalty income is recognized monthly as it accrues in accordance with the terms of the royalty agreements.

When allocating the transaction price realized in contracts with multiple performance obligations, management is required to make estimates of the prices at which the Company would sell the product separately to customers. The Company does not currently have any contracts with multiple performance obligations.

See Note 14 for additional disclosures required by IFRS 15.

b) Accounting standards, interpretations and amendments to existing standards not yet effective

IFRS 16 "Leases"

IFRS 16, "Leases" was issued in January 2016 and replaces IAS 17 "Leases". Under the new standard, a single recognition and measurement model for leases is introduced which brings most leases on-balance sheet for the lessees, eliminating the distinction between operating and finance leases. A right-of-use asset and a corresponding liability will be recognized for all leases by the lessee except for short-term leases and leases of low value assets.

On adoption, non-current assets, current liabilities and non-current liabilities on the Corporation's consolidated statement of financial position will increase, as many of the Corporations' existing operating lease arrangements will meet the definition of a lease under IFRS 16 and thus be recognized in the statement of financial position as a right-of-use asset with a corresponding liability. In addition, the nature of expenses related to these arrangements will change as the current presentation of operating lease expense will be replaced with a depreciation charge for the right-of-use asset and interest expense on the lease liabilities. As well, the classification of cash flows will be impacted as the current presentation of operating lease payments as operating cash flows will be split into financing (principal portion) and operating (interest portion) cash flows under IFRS 16. Additional disclosures will also be required under IFRS 16.

The Company plans to apply IFRS 16 initially on January 1, 2019 using the cumulative effect method whereby the cumulative impact of adopting the standard will be recognized in retained earnings as at January 1, 2019 and comparative periods will not be restated. The Company will disclose additional information throughout the latter half of 2018 on the progress of the transition and has yet to quantify the impacts of this standard.

3. TOURMALINE OIL CORP. ("TOU") SHARE INVESTMENT

	June 30, 2018		December 31, 2017	
	Shares *(thousands)*	**Amount** *($thousands)*	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of period	**1,667**	**$ 37,985**	1,847	$ 66,343
Sold	**(11)**	**(278)**	(180)	(5,687)
Unrealized change in fair value	**–**	**1,210**	–	(22,671)
Balance, end of period	**1,656**	**$ 38,917**	1,667	$ 37,985

During the second quarter of 2018, the Company sold 10,700 TOU shares at $25.97 per share, for net cash proceeds of $0.3 million. Proceeds from the sale of TOU shares were used to voluntarily pay down the balance of the TOU share margin loan by $0.3 million.

At June 30, 2018, the Company held 1.66 million (December 31, 2017 – 1.67 million) TOU shares with a fair value of $38.9 million (December 31, 2017 – $38.0 million) based on a June 30, 2018 closing price of $23.49 per share (December 31, 2017 – $22.78 per share). Net loss for the six months ended June 30, 2018 included an unrealized gain of $1.2 million (2017 – $14.2 million unrealized loss) representing the change in fair value of TOU shares held during the period.

At June 30, 2018, 1.66 million TOU shares (December 31, 2017 – 1.67 million TOU shares) were pledged as security for the TOU share margin loan (note 7).

As at June 30, 2018, a $1.00 per share increase in the market price of TOU shares would increase the Company's after tax net income by $1.7 million.

4. PROPERTY, PLANT AND EQUIPMENT ("PP&E")

	Oil and Gas Properties	**Corporate Assets**	**Total**
Cost			
December 31, 2016	$ 611,046	$ 7,182	$ 618,228
Additions	71,008	79	71,087
Acquisitions	233	–	233
Change in decommissioning obligations (note 11)	5,022	–	5,022
Dispositions	(8)	–	(8)
December 31, 2017	$ 687,301	$ 7,261	$ 694,562
Additions	16,382	344	16,726
Change in decommissioning obligations (note 11)	379	–	379
Dispositions	(848)	–	(848)
June 30, 2018	**$ 703,214**	**$ 7,605**	**$ 710,819**
Accumulated depletion, depreciation and impairment losses			
December 31, 2016	$ (391,439)	$ (6,903)	$ (398,342)
Depletion and depreciation	(33,226)	(210)	(33,436)
December 31, 2017	(424,665)	(7,113)	(431,778)
Depletion and depreciation	(18,849)	(58)	(18,907)
June 30, 2018	**$ (443,514)**	**$ (7,171)**	**$ (450,685)**
Carrying amount			
December 31, 2017	$ 262,636	$ 148	$ 262,784
June 30, 2018	**$ 259,700**	**$ 434**	**$ 260,134**

At June 30, 2018, property, plant and equipment included $1.7 million (December 31, 2017 – $1.3 million) of costs currently not subject to depletion.

a) Dispositions

Proceeds (payments) on dispositions

($ thousands)	Three months ended June 30, **2018**	2017	Six months ended June 30, **2018**	2017
Proceeds from dispositions of oil and gas properties	**12,149**	–	**12,152**	436
Proceeds from retained shallow gas marketing arrangements	**–**	331	**–**	869
Payments on retained shallow gas marketing arrangements	**(4,527)**	(940)	**(5,456)**	(1,869)
Net proceeds (payments) on dispositions	**7,622**	(609)	**6,696**	(564)

Gain (loss) on dispositions

($ thousands)	Three months ended June 30, **2018**	2017	Six months ended June 30, **2018**	2017
Proceeds from dispositions of oil and gas properties	**12,149**	–	**12,152**	436
Carrying amount of PP&E and E&E disposed, net of ARO	**(11,415)**	–	**(11,415)**	(8)
Realized gain from retained shallow gas marketing arrangements	**–**	331	**–**	869
Unrealized loss on retained shallow gas marketing arrangements	**–**	(1,363)	**(874)**	(4,520)
Gain (loss) on dispositions	**734**	(1,032)	**(137)**	(3,223)

Dispositions during the six months ended June 30, 2018 included the sale of non-core royalty interests and exploration and evaluation properties for gross proceeds of $12.2 million, resulting in a net gain on oil and gas properties of $0.7 million. Included in the gain was $0.4 million in liabilities related to decommissioning obligations associated with the non-core properties that were sold.

On October 1, 2016, Perpetual sold 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 Disposition"). The Shallow Gas Disposition also included marketing arrangements whereby the Company provided floor price protection at $2.58/GJ to the purchaser and retained price exposure to the extent average monthly AECO prices exceed $2.81/GJ on 33,611 GJ/d through to August 31, 2018. The Company entered into marketing arrangements prior to closing to fix the cost of the floor price protection through to March 31, 2018. Realized and unrealized gains and losses on these marketing arrangements are recognized as adjustments to gains/losses on dispositions and included as cash flows from investing activities on the consolidated statement of cash flows.

As at June 30, 2018, the net retained shallow gas marketing arrangements have been summarized as follows:

Term	**Volumes at AECO (*GJ/d*)**	**Floor price (*$/GJ*)**	**Ceiling price (*$/GJ*)**	**Fair value (*$ thousands*)**
July 2018 – August 2018	33,611	–	2.81	–
July 2018 – August 2018[1]	33,611	2.58	–	(3,083)

[1] During the first quarter of 2018, Perpetual fixed the cost of the floor price protection for the remaining period from April 1, 2018 to August 31, 2018 at a cost of $7.6 million, resulting in an unrealized loss of $0.9 million (2017 – $4.5 million). At June 30, 2018, $3.1 million remains to be paid over the July to August 2018 period.

5. EXPLORATION AND EVALUATION ("E&E")

	June 30, 2018	December 31, 2017
Balance, beginning of period	**$ 46,704**	$ 47,159
Additions	**202**	1,948
Acquisitions	**610**	199
Dispositions	**(10,947)**	–
Non-cash exploration and evaluation expense	**–**	(2,602)
Balance, end of period	**$ 36,569**	$ 46,704

During the six months ended June 30, 2018, $0.3 million (2017 – $0.3 million) in costs were charged directly to E&E expense in the consolidated statements of net loss.

6. CAPITAL MANAGEMENT

Perpetual's strategy includes maintaining a strong capital base to retain investor, creditor and market confidence and to support the execution of its business plan. The Company manages its capital structure and makes adjustments to 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, revolving bank debt, the term loan, TOU share margin loan 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.

The Company will continue to regularly assess changes to its capital structure and repayment alternatives, with considerations for both short term liquidity, investment opportunities and longer term financial sustainability.

7. TOU SHARE MARGIN LOAN

At June 30, 2018, Perpetual had a $15.7 million TOU share margin loan ($15.7 million principal amount) secured by 1.66 million TOU shares that matures on July 31, 2018. Interest rates are indexed to the same applicable Banker's Acceptance margins as the Credit Facility (note 8) 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 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%.

During the quarter ended June 30, 2018, Perpetual sold 10,700 TOU shares at $25.97 per share and used the proceeds of $0.3 million to partially repay the TOU share margin loan. As at June 30, 2018, the Lending Ratio was 40% of the closing market value of the pledged TOU shares. The TOU share margin loan is designated as a financial liability for accounting purposes and measured at amortized cost.

The effective interest rate on the TOU share margin loan as at June 30, 2018 was 4.1%. For the period ended June 30, 2018, if interest rates changed by 1%, with all other variables held constant, the impact on annual interest expense and net loss would be $0.2 million.

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 as at June 30, 2018.

On July 31, 2018, the TOU share margin loan was converted into a demand loan with the same lender, with similar terms and conditions. Interest rates are based on Banker's Acceptance rates plus 1.25%.

8. REVOLVING BANK DEBT

As at June 30, 2018, the Company's reserve-based revolving credit facility (the "Credit Facility") had a borrowing limit (the "Borrowing Limit") of $60 million (December 31, 2017 – $65.0 million) under which $42.8 million was drawn (December 31, 2017 – $31.6 million) and $3.7 million of letters of credit had been issued (December 31, 2017 – $3.9 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%.

On May 7, 2018, the Borrowing Limit was reduced from $65.0 million to $60.0 million, with the next Borrowing Limit redetermination scheduled on or prior to November 30, 2018. If not extended, the Credit Facility will cease to revolve, and all outstanding advances will be repayable on May 31, 2019. As the Credit Facility now matures in less than one year, revolving bank debt has been presented as a current liability on the condensed interim consolidated statement of financial position as at June 30, 2018.

The Credit Facility is secured by general security agreements covering all of the Company's assets, with the exception of the TOU shares that have been pledged as security for the TOU share margin loan (note 7) and certain lands pledged to the gas over bitumen royalty financing counterparty. The Credit Facility also contains provisions which restrict the Company's ability to pay dividends on or repurchase its common shares.

The effective interest rate on the Credit Facility at June 30, 2018 was 4.6%. For the period ended June 30, 2018, if interest rates changed by 1% with all other variables held constant, the impact on annual interest expense and net loss would be $0.4 million (Q2 2017 – nil).

At June 30, 2018, the Credit Facility was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

9. 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 (note 12).

	June 30, 2018	December 31, 2017
Balance, beginning of period	**$ 43,233**	$ –
Principal amount of term loan issued	**–**	45,000
Value allocated to warrants issued	**–**	(769)
Issue costs	**–**	(1,361)
Amortization of issue costs	**243**	363
Balance, end of period	**$ 43,476**	$ 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. 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 (note 8). 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 June 30, 2018, the term loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

10. SENIOR NOTES

	Maturity date	Interest rate	June 30, 2018 Principal	June 30, 2018 Carrying Amount	December 31, 2017 Principal	December 31, 2017 Carrying amount
2019 senior notes	July 23, 2019	8.75%	**14,572**	**14,506**	14,572	14,476
2022 senior notes	January 23, 2022	8.75%[(1)]	**17,918**	**17,266**	17,918	17,204
			$ 32,490	**$ 31,772**	$ 32,490	$ 31,680

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

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

The senior notes are direct senior unsecured obligations of the Company, ranking pari passu with all other present and future unsecured and unsubordinated indebtedness of the Company. At any time prior to three years before the senior note maturity date, the Company can redeem up to 35 percent of the principal amount of the senior notes at a premium to face value. Within three years of maturity, the Company may redeem up to 100 percent of the senior notes at a premium to face value. Within one year of maturity, the Company may redeem up to 100 percent of the senior notes at the principal amount.

The senior notes have a cross-default provision with the Company's Credit Facility (note 8). In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt and stock repurchases. The permitted amount of any restricted payment is limited to:

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

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

At June 30, 2018 the senior notes are presented net of $0.7 million in issue costs which are amortized using a weighted average effective interest rate of 9.6%.

At June 30, 2018, other than the restricted payment covenants noted above, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

11. PROVISIONS

	June 30, 2018	December 31, 2017
Decommissioning obligations	**$ 36,589**	$ 37,081
Restructuring costs	**1,369**	1,604
Total provisions	**$ 37,958**	$ 38,685
Provisions – current	**$ 2,002**	$ 2,580
Provisions – non-current	**35,956**	36,105
	$ 37,958	$ 38,685

a) Decommissioning obligations

The following significant assumptions were used to estimate decommissioning obligations:

	June 30, 2018	December 31, 2017
Decommissioning obligations, beginning of period	**$ 37,081**	$ 33,620
Obligations incurred	**379**	1,554
Obligations settled	**(906)**	(2,336)
Obligations disposed	**(380)**	–
Accretion (note 15)	**415**	775
Change in risk free interest rate	**–**	2,339
Change in estimates	**–**	1,129
Decommissioning obligations, end of period	**$ 36,589**	$ 37,081
Decommissioning obligations – current	**$ 1,799**	$ 2,243
Decommissioning obligations – non-current	**34,790**	34,838
	$ 36,589	$ 37,081

Total future decommissioning obligations are estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, and the estimated timing of the costs to be incurred in future periods.

The following significant assumptions were used to estimate the Company's decommissioning obligations:

	June 30, 2018	December 31, 2017
Undiscounted obligations	**$ 37,619**	$ 38,525
Average risk-free rate	**2.3%**	2.3%
Inflation rate	**2.0%**	2.0%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

b) Restructuring costs

	Employee downsizing costs	Onerous office lease contract	Lease inducement	Total
Balance, December 31, 2016	$ 1,606	$ 2,548	$ –	$ 4,154
Transferred	–	(1,764)	1,764	–
Payments	(1,606)	(650)	(294)	(2,550)
Balance, December 31, 2017	–	134	1,470	1,604
Payments	–	(134)	(101)	(235)
Balance, June 30, 2018	**–**	**–**	**1,369**	**1,369**
Restructuring costs – current	–	–	203	203
Restructuring costs – non-current	–	–	1,166	1,166
Total	**$ –**	**$ –**	**$ 1,369**	**$ 1,369**

On February 1, 2017, Perpetual entered a new head office lease at its current location for a 98-month period expiring March 31, 2025. As consideration, the landlord agreed to release the Company from all remaining obligations under its existing lease with remaining term to March 31, 2018 and remaining payments of $1.8 million were deferred over the 98-month term of the new lease. This lease inducement is comprised of $1.8 million related to surplus office space which was recognized as an onerous contract provision in 2016. The lease inducement is being amortized on a straight-line basis over the 98-month term of the new head office lease.

12. SHARE CAPITAL

	June 30, 2018		December 31, 2017	
	Shares *(thousands)*	**Amount *($thousands)***	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of period	**59,263**	**$ 1,336,838**	53,421	$ 1,325,705
Issued pursuant to private placement (c)	**–**	**–**	5,143	8,968
Issued pursuant to share-based payment plans	**1,126**	**1,154**	887	1,728
Shares held in trust purchases (b)	**(339)**	**(250)**	(708)	(1,000)
Shares held in trust issued (b)	**319**	**514**	520	1,437
Balance, end of period	**60,369**	**$ 1,338,256**	59,263	$ 1,336,838

a) Authorized

Authorized capital consists of an unlimited number of common shares.

b) Shares held in trust

The Company has compensation agreements in place with employees whereby they may be entitled to receive shares of the Company purchased on the open market by a trustee (note 13d). Share capital is presented net of the number and cumulative purchase cost of shares held by the trustee that have not yet been issued to employees. As at June 30, 2018, 467,000 shares were held in trust (December 31, 2017 – 447,000).

c) Warrants and equity private placement

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 resulting in the issuance of 5,143,000 shares and 1,080,000 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 (note 9). Each warrant entitles the holder to acquire common shares on a one for one basis at an exercise price of $2.34 per share prior to March 14, 2020.

The following table summarizes the warrants and common shares issued:

	June 30, 2018			
	Shares (*thousands*)	**Amount** (*$thousands*)	**Warrants** (*thousands*)	**Amount** (*$thousands*)
Balance, December 31, 2016	–	$ –	–	$ –
Issued through term loan	–	–	5,400	769
Issued through private placement	5,143	8,968	1,080	154
Balance, December 31, 2017	5,143	$ 8,968	6,480	$ 923
Warrants exercised for common shares	–	–	–	–
Balance, June 30, 2018	**5,143**	**$ 8,968**	**6,480**	**$ 923**

If the volume weighted average price of Perpetual's common shares is greater than $2.34 per share 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.

d) Per share information

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
(*thousands, except per share amounts*)				
Net loss – basic	**$ (1,325)**	$ (7,219)	**$ (7,790)**	$ (21,391)
Effect of dilutive securities	**–**	–	**–**	–
Net loss – diluted	**$ (1,325)**	$ (7,219)	**$ (7,790)**	$ (21,391)
Weighted average shares				
Issued common shares	**60,416**	59,391	**60,090**	57,072
Effect of shares held in trust	**(540)**	(346)	**(478)**	(303)
Weighted average common shares outstanding – basic and diluted	**59,876**	59,045	**59,612**	56,769
Income (loss) per share – basic and diluted	**$ (0.02)**	$ (0.12)	**$ (0.13)**	$ (0.38)

In computing per share amounts for the three months ended June 30, 2018, 1.6 million potentially issuable common shares through the share-based compensation plans (Q2 2017 – 1.1 million) and warrants were excluded as the Corporation had a net loss. In computing per share amounts for the six months ended June 30, 2018, 1.4 million potentially issuable common shares through the share-based compensation plans (2017 – 1.3 million) and warrants were excluded as the Corporation had a net loss.

13. SHARE-BASED PAYMENTS

The components of share-based payments are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
Share options	**220**	185	**459**	504
Restricted rights	**–**	–	**–**	73
Performance share rights	**170**	187	**422**	477
Compensation awards	**303**	613	**618**	1,463
Share-based payments	**693**	985	**1,499**	2,517

a) Share option plan

Perpetual's share option plan provides a long-term incentive to employees and directors associated with the Company's long-term performance. The Board of Directors administers the share option plan and determines participants, number of share options and terms of vesting. The exercise price of the share options granted shall not be less than the value of the weighted average trading price for the Company's common shares for the five trading days immediately preceding the date of grant. Share options granted vest evenly over 4 years, with expiry occurring 5 years after issuance.

The following tables summarize information about share options outstanding:

	June 30, 2018		December 31, 2017	
	Average exercise price (*$/share*)	**Share options (*thousands*)**	Average exercise price (*$/share*)	Share options (*thousands*)
Balance, beginning of period	**1.67**	**3,987**	1.71	2,068
Granted	**–**	**–**	1.71	2,015
Cancelled/forfeited	**1.66**	**(83)**	–	–
Expired	**–**	**–**	3.23	(96)
Balance, end of period	**1.67**	**3,904**	1.67	3,987

	Options outstanding			**Options exercisable**	
Range of exercise prices	**Number of share options (*thousands*)**	**Average contractual life (*years*)**	**Weighted average exercise price (*$/share*)**	**Number of share options (*thousands*)**	**Weighted average exercise price (*$/share*)**
$1.15 to $1.29	40	4.3	1.15	–	–
$1.30 to $1.57	1,765	2.9	1.42	882	1.42
$1.58 to $1.86	1,935	3.9	1.72	484	1.72
$1.87 to $5.97	164	1.1	4.01	124	4.67
Total	3,904	3.3	1.67	1,490	1.79

The Company used the Black Scholes pricing model to calculate the estimated fair value of the outstanding share options at the date of grant. During the six months ended June 30, 2018, the Company did not grant any additional share options.

b) Restricted rights plan

The Company has a restricted rights plan for certain officers, employees and consultants. Restricted rights granted under the restricted rights plan may be exercised during a period (the “Exercise Period”) not exceeding five years from the date upon which the restricted rights were granted. The restricted rights typically vest on a graded basis over two years. At the expiration of the Exercise Period, any restricted rights which have not been exercised shall expire. Upon vesting, the plan participant is entitled to receive one common share for each right held at a cost of $0.01 per share.

The fair value of an award granted under the restricted rights plan is assessed on the grant date by factoring in the weighted average common share trading price for the five days preceding the grant date. This fair value is recognized as share-based payment expense over the vesting period with a corresponding increase to contributed surplus. Upon exercise of restricted rights, the value in contributed surplus pertaining to the exercise is recorded as shareholders capital. During the six months ended June 30, 2018, the Company did not grant any restricted rights to employees, other than to settle performance share rights and deferred shares.

Restricted rights granted upon the exercise of performance share units (note 13c) and deferred shares (note 13d) vest on the grant date and generally have a 30-day exercise period. No value is assigned to restricted rights issued pursuant to those plans as the value and expense has been recognized over the vesting period of the underlying performance share units and deferred shares.

The following table shows changes in the restricted rights outstanding under the restricted rights plan:

(*thousands*)	**June 30, 2018**	December 31, 2017
Balance, beginning of period	**–**	273
Granted to employees	**–**	44
Granted pursuant to exercise of performance share rights (c)	**1,008**	209
Granted pursuant to exercise of deferred shares (d)	**166**	369
Exercised for common shares	**(1,135)**	(895)
Balance, end of period	**39**	–

c) Performance share rights plan

The Company has a performance share rights plan for the executive management team. Performance rights granted under the performance share rights plan vest two years after the date upon which the performance rights were granted. The performance rights that vest and become redeemable are a multiple of the performance rights granted, dependent upon the achievement of certain performance metrics over the vesting period. Vested performance rights can be settled in cash or restricted rights (note 13b), at the discretion of the Board of Directors. Should participants of the performance share rights plan leave the organization other than through retirement or termination without cause prior to the vesting date, the performance share rights would be forfeited.

The fair value of an award granted under the performance share rights plan is determined at the date of grant by using the closing price of common shares multiplied by the estimated performance multiplier. As at June 30, 2018, performance multipliers of 1.0 have been assumed for those unvested awards granted in 2017 and 2018. Fluctuations in share-based payment expense may occur due to changes in estimates of performance outcomes. The amount of share-based payment expense is reduced by an estimated forfeiture rate of 5% (2017 – 5%) for outstanding awards. The estimated weighted average fair value of performance share rights granted during the six months ended June 30, 2018 was $0.64 per award (2017 – $1.68).

The following table shows changes in the performance share rights outstanding under the performance share rights plan:

(*thousands*)	**June 30, 2018**	December 31, 2017
Balance, beginning of period	**1,060**	1,048
Granted	**1,035**	430
Exercised in exchange for restricted rights[1]	**(630)**	(418)
Balance, end of period	**1,465**	1,060

[1] In 2018, performance share rights were exercised in exchange for restricted rights based on a performance multiplier of 1.6 (2017 – 0.5).

d) Deferred compensation awards

Deferred options

The Company has deferred option agreements in place with certain employees whereby they may be entitled to receive shares of the Company purchased on the open market by an independent trustee if they remain employees of the Company during such time and exercise their options. Deferred options generally vest evenly over 4 years, with expiry occurring 5 years after issuance. The shares purchased by the independent trustee are reported as shares held in trust (note 12b).

The following tables summarize information about the deferred options:

	June 30, 2018		December 31, 2017	
	Average exercise price (*$/share*)	**Deferred options (*thousands*)**	Average exercise price (*$/share*)	Deferred options (*thousands*)
Balance, beginning of period	**1.68**	**2,268**	1.69	1,072
Granted	**–**	**–**	1.72	1,380
Cancelled/forfeited	**1.66**	**(219)**	1.74	(120)
Expired	**2.52**	**(15)**	2.55	(64)
Balance, end of period	**1.68**	**2,034**	1.68	2,268

	Deferred options outstanding			**Deferred options exercisable**	
Range of exercise prices	**Number of deferred options (*thousands*)**	**Average contractual life (*years*)**	**Weighted average exercise price (*$/share*)**	**Number of deferred options (*thousands*)**	**Weighted average exercise price (*$/share*)**
$1.30 to $1.57	741	2.9	1.42	370	1.42
$1.58 to $1.86	1,224	3.9	1.72	306	1.72
$1.87 to $5.97	69	1.3	3.65	50	4.31
Total	2,034	3.5	1.68	726	1.74

The Company used the Black Scholes pricing model to calculate the estimated fair value of deferred options at the date of grant. During the six months ended June 30, 2018, the Company did not grant any additional deferred options.

Deferred shares

The Company also has deferred share agreements in place with directors and certain employees whereby, in the case of directors, upon retirement from the board of directors, or in the case of employees, over a period of two years if they remain employees of the Company during such time, may be entitled to receive at the discretion of the Board, cash, a grant of restricted rights (note 13b) or shares of the Company purchased on the open market by an independent trustee. The shares purchased by the independent trustee are reported as shares held in trust (note 12b).

The fair value of these agreements is assessed on the grant date by factoring in the weighted average common share trading price for the five days preceding the grant date and is reduced by an estimated forfeiture rate of 5% (2017 – 5%). The fair value is recognized as share-based payment expense over the vesting period with a corresponding increase to contributed surplus. Upon exercise of these agreements in exchange for restricted rights, the value in contributed surplus pertaining to the exercise is recorded as shareholders capital. Upon exercise of these agreements in exchange for shares held in trust, the shares held in trust account is reduced by the number of shares issued using the average cost base of purchased shares and offset to contributed surplus. During the six months ended June 30, 2018, the Company did not grant any additional deferred shares.

The following table shows changes to these awards:

(*thousands*)	**June 30, 2018**	December 31, 2017
Balance, beginning of period	**1,857**	2,197
Granted	**–**	684
Exercised in exchange for shares held in trust (note 12)	**(321)**	(520)
Exercised in exchange for restricted rights	**(166)**	(369)
Cancelled/forfeited	**(70)**	(135)
Balance, end of period	**1,300**	1,857

14. REVENUE

On January 1, 2018, the Company adopted IFRS 15 “Revenue from Contracts with Customers” as detailed in Note 2, using the cumulative effect method. For the six months ended June 30, 2018, there was no impact to oil and natural gas revenues as a result of adopting IFRS 15.

The Company sells its production pursuant to fixed or variable price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable volumes of natural gas, crude oil or NGLs as may be applicable to the contract counterparty. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company’s efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

Natural gas, crude oil and NGLs are mostly sold under contracts of varying price and volume terms of up to one year. Revenues are typically collected on the 25th day of the month following production.

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

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

The following table presents the Company's oil and natural gas sales disaggregated by revenue source:

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
Oil and natural gas revenue				
Natural gas[(1)]	**11,254**	12,667	**26,705**	25,230
Oil	**5,063**	4,380	**8,553**	7,831
NGL	**4,457**	2,681	**8,856**	4,825
Total oil and natural gas revenue	**20,774**	19,728	**44,114**	37,886

(1) Includes revenues related to the market diversification contract and physical forward sales contracts which settled during the period.

Included in accounts receivable at June 30, 2018 is $6.3 million of accrued oil and natural gas sales related to June 2018 production (December 31, 2017 – $8.0 million related to December 2017 production).

15. FINANCE EXPENSE

The components of finance expense are as follows:

	Three months ended June 30,		Six months ended June 30,	
	2018	2017	**2018**	2017
Cash interest expense and income				
Interest on revolving bank debt	**504**	204	**972**	384
Interest on TOU share margin loan	**162**	87	**310**	301
Interest on term loan	**907**	709	**1,818**	854
Interest on senior notes	**722**	921	**1,443**	2,279
Dividend income from TOU share investment	**(152)**	–	**(285)**	–
Total cash interest expense and income	**2,143**	1,921	**4,258**	3,818
Non-cash finance expense				
Amortization of debt issue costs	**267**	189	**517**	283
Accretion on decommissioning obligations (note 11)	**208**	195	**415**	386
Change in fair value of gas over bitumen royalty financing	**198**	33	**68**	(1,206)
Change in fair value of TOU share put option margin loans	**–**	504	**–**	1,425
Total non-cash finance expense	**673**	921	**1,000**	888
Finance expenses recognized in net loss	**2,816**	2,842	**5,258**	4,706

16. FINANCIAL RISK MANAGEMENT

Realized gains on commodity price derivatives recognized in net loss for the six months ended June 30, 2018 were $1.7 million (2017 – $0.9 million). The realized gains on commodity price derivatives for the six months ended June 30, 2018 did not include the early settlement of any contracts prior to their maturity.

Natural gas contracts

At June 30, 2018 the Company had entered into the following physical fixed price natural gas sales arrangements at AECO:

Term	Sold/bought	Volumes (*GJ/d*)	Average price (*$/GJ*)	Fair Value (*$ thousands*)
September 2018 – March 2019	Sold	5,000	1.40	(422)

At June 30, 2018 the Company had entered into the following financial fixed price natural gas sales arrangements at AECO:

Term	Sold/bought	Volumes (*GJ/d*)	Average price (*$/GJ*)	Fair Value (*$ thousands*)
July 2018 – October 2018	Sold	10,000	2.06	697
July 2018 – March 2019	Sold	10,000	1.41	(819)

At June 30, 2018 the Company had entered into the following physical basis differential contracts between AECO and NYMEX:

Term	Sold/bought	Volumes (*MMBtu/d*)	AECO-NYMEX differential (*US$/MMBtu*)	Fair Value (*$ thousands*)
July 2018 – October 2018	Sold	7,500	(1.80)	243
July 2018 – October 2018	Bought	(7,500)	(1.92)	(66)
August 2018	Bought	(25,000)	(1.86)	117
November 2018 – March 2019	Sold	7,500	(1.55)	(56)
January 2019 – December 2019	Sold	12,500	(1.54)	(380)
January 2020 – December 2020	Sold	12,500	(1.41)	(74)
January 2021 – December 2021	Sold	5,000	(1.15)	340

At June 30, 2018 the Company had entered into the following financial basis differential contracts between AECO and NYMEX:

Term	Sold/bought	Volumes (*MMBtu/d*)	AECO-NYMEX differential (*US$/MMBtu*)	Fair Value (*$ thousands*)
July 2018	Bought	(10,000)	(2.00)	67
July 2018 – October 2018	Sold	5,000	(1.87)	(106)
January 2019 – December 2019	Sold	7,500	(1.50)	(94)
January 2020 – December 2020	Sold	15,000	(1.41)	(38)

Natural gas contracts - sensitivity analysis

As at June 30, 2018, if future natural gas prices changed by $0.25 per GJ with all other variables held constant, the fair value of commodity price derivatives and after tax net loss for the period would change by $5.2 million. Fair value sensitivity was based on published forward AECO and NYMEX prices.

Oil contracts

At June 30, 2018, the Company had entered into the following fixed price oil contracts which settle in US$:

Term	Volumes at WTI (*bbls/d*)	Fixed price (*US$/bbl*)	Fair Value (*$ thousands*)
July 2018 – December 2018	250	63.74	(416)

At June 30, 2018, the Company had entered into the following costless collar oil sales arrangements which settle in US$:

Term	Volumes at WTI (*bbls/d*)	Floor price (*US$/bbl*)	Ceiling price (US*$bb*l)	Fair Value (*$ thousands*)
July 2018 – December 2018	250	50.00	58.40	(759)
July 2018 – December 2018	250	50.00	60.00	(674)

At June 30, 2018, the Company had entered into the following oil basis differential contracts between WTI and WCS trading:

Term	Volumes at WTI (*bbls/d*)	WTI-WCS differential (*US$/bbl*)	Fair Value (*$ thousands*)
July 2018	500	(19.75)	14

Oil contracts - sensitivity analysis

As at June 30, 2018, if future oil prices changed by $5.00 per boe with all other variables held constant, the fair value of commodity price derivatives and after tax net loss for the period would change by $0.8 million. Fair value sensitivity was based on published forward WTI and WCS prices.

Foreign exchange contracts

At June 30, 2018, the Company had entered into the following US$ forward sales arrangements to manage the Company's exposure to US$ denominated oil and NGL commodity sales:

Term	Notional (*US$/month*)	Strike rate (*US$/Cdn$*)	Fair Value (*$ thousands*)
July 2018 – October 2018	1,500,000	1.30	(56)

At June 30, 2018, the Company had entered into the following US$ forward sales arrangements to manage the Company's exposure to US$ denominated natural gas sales:

Term	Notional (*US$/month*)	Strike rate (*US$/Cdn$*)	Fair Value (*$ thousands*)
July 2018 – October 2018	2,000,000	1.30	(137)
November 2018 – March 2019	1,500,000	1.30	(77)
April 2019 – October 2019	1,000,000	1.32	92

Foreign exchange contracts - sensitivity analysis

As at June 30, 2018, if future exchange rates changed by $0.10 US$/Cdn$ with all other variables held constant, the fair value of foreign exchange derivatives and after tax net loss for the period would change by $2.0 million. Fair value sensitivity was based on published forward US$/Cdn$ rates.

The following table is a summary of the fair value of the Company's commodity price derivative contracts by type:

	June 30, 2018	December 31, 2017
Physical natural gas contracts	**$ 8**	$ 1,209
Financial natural gas contracts	**(228)**	1,506
Financial oil contracts	**(1,835)**	156
Financial foreign exchange contracts	**(178)**	–
Fixed portion of retained shallow gas marketing arrangements[1]	**(3,083)**	(929)
Non-fixed portion of retained shallow gas marketing arrangements	**–**	(6,736)
Fair value of derivatives	**$ (5,316)**	$ (4,794)
Derivative assets – current	**185**	1,585
Derivative assets – non-current	**132**	1,506
Derivative liabilities – current	**(5,489)**	(7,885)
Derivative liabilities – non-current	**(144)**	–
Fair value of derivatives	**$ (5,316)**	$ (4,794)

(1) The Company has fixed the cost of net retained shallow gas obligations at $3.1 million to be paid over the remaining July to August 2018 period.

The following table details the Company's changes in fair value of commodity price derivatives:

	Three months ended June 30, **2018**	2017	Six months ended June 30, **2018**	2017
Unrealized gain (loss) on financial natural gas contracts	**(2,168)**	59	**(1,734)**	(3,561)
Unrealized gain (loss) on physical natural gas contracts	**747**	882	**(1,201)**	1,489
Unrealized gain (loss) on financial oil contracts	**(1,179)**	188	**(1,991)**	1,425
Unrealized gain (loss) on forward foreign exchange contracts	**(178)**	–	**(178)**	5,022
Unrealized change in fair value of commodity price derivatives	**(2,778)**	1,129	**(5,104)**	4,375
Realized gain on financial natural gas contracts	**1,450**	354	**1,717**	6,253
Realized gain (loss) on financial oil contracts	**(357)**	(192)	**67**	(1,166)
Realized loss on forward foreign exchange contracts	**(45)**	–	**(45)**	(4,178)
Change in fair value of commodity price derivatives	**(1,730)**	1,291	**(3,365)**	5,284

Fair value of financial assets and liabilities

The Company's fair value measurements are classified as one of the following levels of the fair value hierarchy:

Level 1 – inputs represent unadjusted quoted prices in active markets for identical assets and liabilities. An active market is characterized by a high volume of transactions that provides pricing information on an ongoing basis.

Level 2 – inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly. These valuations are based on inputs that can be observed or corroborated in the marketplace, such as market interest rates or forward prices for commodities.

Level 3 – inputs for the asset or liability are not based on observable market data.

The Company aims to maximize the use of observable inputs when preparing calculations of fair value. Classification of each measurement into the fair value hierarchy is based on the lowest level of input that is significant to the fair value calculation.

The fair value of cash and cash equivalents, accounts receivable, and accounts payable and accrued liabilities approximate their carrying amounts due to their short terms to maturity. Revolving bank debt and the TOU share margin loan bear interest at a floating market rate, and accordingly, the fair market value approximates the carrying amount.

The fair value of the gas over bitumen royalty financing is estimated by discounting future cash payments based on the forecasted Alberta gas reference price multiplied by the contracted deemed volume. This fair value measurement is classified as level 3 as significant unobservable inputs, including the discount rate and forecasted Alberta gas reference prices, are used in determination of the carrying amount. The discount rate of 12.2% was determined on inception of the agreement based on the characteristics of the instrument. The forecasted Alberta gas reference prices for the remaining term are based on AECO forward market pricing with adjustments for historical differences between the Alberta reference price and market prices.

The fair value of financial assets and liabilities, excluding working capital, is attributable to the following fair value hierarchy levels:

				Fair value		
As at June 30, 2018	**Gross**	**Netting[(1)]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
TOU share investment	**38,917**	**–**	**38,917**	**38,917**	**–**	**–**
Derivatives	**2,294**	**(1,977)**	**317**	**–**	**317**	**–**
Financial liabilities						
Financial liabilities at amortized cost						
TOU share margin loan	**15,699**	**–**	**15,699**	**15,714**	**–**	**–**
Revolving bank debt	**42,752**	**–**	**42,752**	**42,917**	**–**	**–**
Senior notes	**31,772**	**–**	**31,772**	**–**	**32,490**	**–**
Term loan	**43,476**	**–**	**43,476**	**–**	**–**	**45,000**
Fair value through profit and loss						
Derivatives	**7,610**	**(1,977)**	**5,633**	**–**	**5,633**	**–**
Gas over bitumen royalty financing	**2,108**	**–**	**2,108**	**–**	**–**	**2,108**

(1) Derivative assets and liabilities presented in the statement of financial position are shown net of offsetting assets or liabilities where the arrangement provides for the legal right, and intention for net settlement exists.

Forward-Looking Information

*Certain information regarding Perpetual in this report including management's assessment of future plans and operations may constitute forward-looking information or statements under applicable securities laws. The forward looking information includes, without limitation, anticipated amounts and allocation of capital spending; statements pertaining to adjusted funds flow levels, statements regarding estimated production and timing thereof; drilling, completion and development activities; infrastructure expansion and construction; prospective oil and natural gas liquids production capability; projected realized natural gas prices and adjusted funds flow; estimated decommissioning obligations; commodity prices and foreign exchange rates; and commodity price management. Various assumptions were used in drawing the conclusions or making the forecasts and projections contained in the forward-looking information contained in this report, which assumptions are based on management's analysis of historical trends, experience, current conditions and expected future developments pertaining to Perpetual and the industry in which it operates as well as certain assumptions regarding the matters outlined above. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks, which could cause actual results to vary and, in some instances, to differ materially from those anticipated by Perpetual and described in the forward-looking information contained in this report. Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described under "Risk Factors" in Perpetual's Annual Information Form and MD&A for the year ended December 31, 2017 and those included in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR website (*www.sedar.com*) and at Perpetual's website (*www.perpetualenergyinc.com*). Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Perpetual's management at the time the information is released and Perpetual disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.*

Non-GAAP Measures

This report contains the terms "adjusted funds flow", "adjusted funds flow per share", "adjusted funds flow per boe", "annualized adjusted funds flow", "cash costs", "net working capital deficiency (surplus)", "net debt and net bank debt", "operating netback" and "realized revenue" which do not have standardized meanings prescribed by 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.

For additional reader advisories in regards to non-GAAP financial measures, including Perpetual's method of calculation and reconciliation of these terms to their corresponding GAAP measures, see the section entitled "Non-GAAP Measures" within the Company's MD&A filed on SEDAR.

Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations and meet its financial obligations. Adjusted funds flow is calculated based on cash flows from operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations since Perpetual believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of our operating areas. Expenditures on decommissioning obligations are managed through our capital budgeting process which considers available adjusted funds flow. The Company has also deducted the change in gas over bitumen royalty financing from adjusted funds flow in order to present these payments net of gas over bitumen royalty credits. 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 Shallow Gas Disposition, which management considers to not be related to cash flow from operating activities. Restructuring costs include employee downsizing costs and surplus office lease obligations. Commencing in the first quarter of 2018, the Company no longer excludes 'exploration and evaluation – geological and geophysical costs, (six months ended June 30, 2018 – nil; and six months ended June 30, 2017 – $0.02 million recovery) from the calculation of adjusted funds flow as these costs are no longer significant to the Company's business. The calculation of adjusted funds flow for comparative periods has been adjusted to give effect to this change. Adjusted funds flow per share is calculated using the same weighted average number of shares outstanding used in calculating earnings per share. Adjusted funds flow is not intended to represent net cash flows from (used in) operating activities calculated in accordance with IFRS. Adjusted funds flow per boe is calculated as adjusted funds flow divided by total production sold in a period.

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

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 the TOU share margin loan 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 share investment, TOU share margin loan 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 costs from realized revenue. Operating netback is also calculated on a per boe basis using production sold for the period. Operating netback on a per boe basis can vary significantly for each of the Company's operating areas.

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 Shallow Gas Disposition. Realized revenue is used by management to calculate the Corporation's net realized commodity prices, taking into account monthly settlements of foreign exchange contracts, 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.

BOE Equivalents

Perpetual's aggregate proved and probable reserves are reported in barrels of oil equivalent (boe). Boe may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 Mcf: 1 boe has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

The following abbreviations used in this report have the meanings set forth below:

bbls	*barrels*
boe	*barrels of oil equivalent*
Mcf	*thousand cubic feet*
MMcf	*million cubic feet*
MMBtu	*million British Thermal Units*
GJ	*gigajoules*

DIRECTORS

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Susan L. Riddell Rose
President, Chief Executive Officer and Director
Robert A. Maitland
Independent Director(1)(2)(3)
Geoffrey C. Merritt
Independent Director(1)(2)(4)
Donald J. Nelson
Independent Director(2)(4)
Ryan A. Shay
Independent Director(1)(3)
Howard R. Ward
Independent Director(3)(4)

(1) Member of Audit Committee
(2) Member of Reserves Committee
(3) Member of Compensation and Corporate Governance Committee
(4) Member of Environmental, Health & Safety Committee

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REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company