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 relative to the first quarter of 2017. Production growth of 56% relative to the prior year period combined with a 34% reduction in unit operating costs, a 23% reduction in royalty rate and a 9% reduction in transportation costs per boe to drive strong operational performance metrics through focused operations. Corporate cash costs were also materially reduced during the quarter, with cash general and administrative costs and interest on a unit-of-production basis down 32% and 29% respectively compared to Q1 2017. These factors translated into solid growth in cash flow from operating activities, after adjusting for changes in non-cash working capital, of 119% and adjusted funds flow growth of 78% despite the hostile commodity price environment in Western Canada, particularly for natural gas.

Natural gas prices in Alberta continued to experience weakness during the quarter, with average AECO Daily Index prices 23% lower than a year ago. In mid-2017, AECO prices became disconnected from the North American market as strong Western Canada supply growth met infrastructure bottlenecks and take away capacity constraints. Perpetual's proactive market diversification strategy implemented in 2017 provided a 20% uplift to prices during the first quarter and importantly will continue to provide for enhanced value and risk management through the expected future periods of volatile natural gas prices in Western Canada due to market access constraints over the coming months. Heavy oil prices, as measured by the price of Western Canadian Select, were close to flat year over year despite the over 20% increase in the West Texas Intermediate benchmark price, again driven by market access constraints in Western Canada related to pipeline construction delays. Supply management by producers and more temporary solutions to relieve some of these market constraints are at play, but certainly larger proposed infrastructure projects need to move forward to reduce commodity price volatility and uncertainty in Western Canada in the longer term.

FIRST QUARTER 2018 HIGHLIGHTS

- Cash flow from operating activities in the first quarter of 2018 was $11.2 million ($0.19/share) compared to cash flow used in operating activities in the prior year period of $2.3 million. After adjusting for changes in non-cash working capital amounts which are impacted by changes in the timing of collection or payment, cash flow from operating activities increased by 119% over the prior year period.

- Adjusted funds flow in the first quarter of 2018 was $9.1 million ($0.15/share), up 78% over the prior year period of $5.1 million ($0.09/share) due to increased production and lower cash costs, partially offset by lower revenue per boe. Adjusted funds flow per boe was $7.94/boe in the first quarter of 2018, up 14% over the prior year period.

- Production averaged 12,742 boe/d in the first quarter of 2018, up 8% over the fourth quarter of 2017 and 56% over the first quarter of 2017 due to the completion and tie-in of the East Edson drilling program during the second half of 2017 and first quarter of 2018.

- Cash costs were $12.82/boe in the first quarter of 2018, down 31% 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.

- Perpetual's exploration and development spending in the first quarter of 2018 totaled $14.8 million. Capital expenditures included drilling 4 (4.0 net) wells, with 1 (1.0 net) horizontal natural gas well at Edson, as well as 3 (3.0 net) horizontal heavy oil wells at Mannville.

Production and Operations

- Spending at East Edson represented 60% of total exploration and development expenditures in the first quarter of 2018. East Edson capital activity included the drilling of one (1.0 net) extended reach horizontal ("ERH") Wilrich horizontal well and frac and tie-in operations of two wells drilled in the fourth quarter of 2017. The two wells that were frac'd and tied-in to production during the first quarter commenced production in February. Frac and tie-in of the one ERH well drilled during the first quarter was deferred to the fourth quarter of 2018 to align high initial production rates with higher anticipated winter natural gas prices.

- Spending in Eastern Alberta consisted of a three well (3.0 net) multi-lateral horizontal drilling program in the Company's Mannville heavy oil property, one waterflood injector well conversion, one water disposal well conversion and associated facilities. The three oil wells came on production in late March with one infill well producing at type curve expectations and two pool extension wells producing at lower rates than targeted. The disposal facility is working well and the Company expects this to translate into future netback improvements. Pressure response is already apparent from the injector conversion completed in December of 2017, further validating the success of the Mannville waterfloods. Summer drilling plans include the drilling of two (1.3 net) wells, with a third development well planned late in the year if positive pressure response from the new injector continues.

- First quarter production averaged 12,742 boe/d, up 8% from the fourth quarter of 2017 and 56% from 8,143 boe/d produced in the prior year period, reflecting a 79% increase in natural gas and associated natural gas liquids ("NGL") production at East Edson driven by the 2017 and Q1 2018 capital program. 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 to production. Heavy oil production at Eastern Alberta was maintained at 2017 first quarter levels as positive waterflood response in several pools restored pressure support and offset production declines. Production increases from wells drilled and tied-in were not impactful on the first quarter of 2018 as the wells were brought on production at the end of the quarter.

- Perpetual's oil and natural gas revenue, before derivatives and marketing contracts, for the three months ended March 31, 2018 of $23.3 million increased 29% from the first quarter of 2017 due to a 56% increase in average daily production, partially offset by lower natural gas prices.

- Natural gas revenue, before derivatives and marketing contracts, of $15.5 million in the first quarter of 2018 comprised 66% (Q1 2017 – 69%) of total petroleum and natural gas revenue and 86% (Q1 2017 – 83%) of production. Natural gas revenue increased 23% from $12.6 million in 2017 reflecting the impact of the 62% increase in production volumes driven by the 2017 and Q1 2018 East Edson capital program, partially offset by lower AECO natural gas prices. Perpetual's average realized gas price, including derivatives and adjusted for heat content was $2.65/Mcf compared to an AECO Daily Index price of $2.08/Mcf. Perpetual's 35,000 MMBtu/d, five-year term market diversification contract contributed $2.4 million of incremental revenue and increased Perpetual's average realized natural gas price by $0.41/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. Commencing April 1, 2018, volumes delivered to the market diversification contract increased to 40,000 MMBtu/d.

- Oil revenue in the first quarter of $3.5 million represented 15% (Q1 2017 – 19%) of total petroleum and natural gas revenue while oil production was 7% (Q1 2017 – 11%) of total Company production. Perpetual's average realized oil price for the first quarter was $48.31/bbl compared to $31.39/bbl in the first quarter of 2017. Oil revenue was comparable to the same period in 2017 due to similar production levels and WCS average prices, as increases in the WTI US$ benchmark prices were fully offset by the higher WCS differential and a stronger Canadian dollar compared to the prior year period.

- NGL revenue for the first quarter of 2018 of $4.4 million comprised 19% (Q1 2017 – 12%) of total petroleum and natural gas revenue while NGL production was just 7% (Q1 2017 – 6%) of total Company production. NGL revenue increased by 105% over the prior year period as production increased by 77%, tracking the Company's growth in natural gas production at East Edson, combined with a 16% increase in NGL prices compared to the prior year period, positively correlated to the increase in WTI light oil prices.

- Royalty expenses for the quarter ended March 31, 2018 were $3.1 million, comparable to the first quarter 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 17.1% in the prior year period to 13.1% in the first quarter of 2018. The decreased royalty rate is primarily due to a lower effective freehold and overriding royalty rate at East Edson, with the East Edson joint venture take-in-kind royalty effectively a fixed volume over the larger production base in the first quarter of 2018.

- Total production and operating expenses were $4.8 million for the first quarter of 2018, comparable to the prior year period despite the 56% increase in production over the comparable period, primarily from the low-cost East Edson area which averaged $2.05/boe in the first quarter of 2018. The first quarter of 2018 saw higher than average well servicing requirements in the Mannville assets which increased operating costs as well as negatively affected production volumes. Production and operating expenses on a unit-of-production basis were $4.16/boe, a decrease of 34% from the prior year period.

- Transportation costs in the first quarter of 2018 were $1.4 million, up 42% from the prior year period due to increased production from West Central where transportation costs averaged $1.13/boe compared to $2.10/boe for production from Eastern Alberta. Transportation costs were $1.26/boe in the first quarter, down 9% from the prior year period largely due to a higher percentage of production from West Central properties where pipeline tariffs are less than half of transportation rates in Mannville in Eastern Alberta.

- Perpetual's operating netback of $14.8 million in the first quarter of 2018 increased 45% from $10.2 million in the comparative period of 2017 driven by higher production. On a unit-of-production basis, operating netbacks per boe decreased 7% to $12.87/boe due to lower realized commodity prices.

Financial Highlights

- Total G&A expense was $2.89/boe in the first quarter of 2018, down 32% from the prior year period due to reductions in office lease costs, staffing levels and diligent expense management, combined with increased production.

- Total cash interest expense of $2.1 million for the three months ended March 31, 2018 was 11% higher than the prior year period (Q1 2017 – $1.9 million) due to increased debt levels, partially offset by lower interest rates and the initial dividend income of $0.1 million received from the TOU share investment in late March.

- Net loss for the first quarter of 2018 was $6.5 million ($0.11/share), compared to a net loss of $14.2 million ($0.26/share) in the comparative 2017 period. The improvement from the prior year period reflected stronger operational and capital performance including a 56% increase in production, a 31% reduction in cash costs per boe and a 9% reduction in depletion expense per boe, partially offset by a 19% decrease in realized revenue per boe.

- At March 31, 2018, Perpetual had total net debt of $115.1 million, up $9.1 million from December 31, 2017. The increase reflects the first quarter capital expenditures and lower market value of the TOU share investment, partially offset by the reduction of the net working capital deficiency.

- As at March 31, 2018, 55% 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 first quarter of 2018 to 3.3 times at March 31, 2018 (December 31, 2017 – 3.4 times).

2018 STRATEGIC PRIORITIES

During the first quarter of 2018, significant progress was 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

- Spending on East Edson liquids-rich gas projects for the first quarter of 2018 totaled $8.9 million and included the drilling of one (1.0 net) extended reach horizontal ("ERH") natural gas well and frac and tie-in operations of two wells drilled in the fourth quarter of 2017, all targeting Wilrich formation development. The two wells that were frac'd and tied-in during the first quarter commenced production in February.

- Frac and tie-in of the one ERH well drilled during the first quarter at 2-23-51-16W5 was deferred to the fourth quarter of 2018 to align high initial production rates with higher anticipated winter natural gas prices. This ERH well was drilled to 2,953 meters in length and is directly offsetting and parallel to the Company's first ERH well drilled to 2,460 meters at 4-23-51-16W5. The offset well began production in the fourth quarter of 2017 and represented the highest deliverability well drilled to date by Perpetual at East Edson with a thirty-day average initial productivity ("IP30") of 16.4 MMcf/d of natural gas plus associated liquids, over 75% higher than the length-adjusted type curve contained in the 2017 year-end McDaniel reserve report, and continues to produce significantly above this type curve.

- Production in west central Alberta, primarily at East Edson, grew 79% relative to the first quarter of 2017 and 12% as compared to the previous quarter to 11,076 boe/d, comprising 87% of total Company production during the first quarter of 2018. The production growth was driven by the successful Wilrich formation development drilling program.

- Increased production at East Edson, combined with a low variable cost structure, drove West Central operating costs down to $2.05/boe in the first quarter of 2018 (Q1 2017 – $3.75/boe; Q4 2017 – $1.72/boe). Production and operating expenses at East Edson decreased by 45% 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 were $13.28/boe, down just 3% relative to Q1 2017 driven by the low cost structure, despite the 19% decrease in revenue per boe resulting from lower natural gas prices.

- The Company continues to monitor production from a competitor's lower Mannville Ellerslie horizontal well drilled in late 2016 to inform the economic viability of this liquids-rich natural gas zone as a secondary development target at East Edson. Perpetual has 52.8 gross (42.6 net) sections at East Edson in the prospective play fairway. Reported condensate rates from the competitor well have remained relatively steady, averaging 68 bbl/d (68 bbl/MMcf) since inception of production.

Grow value of Eastern Alberta portfolio

- Capital spending in eastern Alberta amounted to $5.9 million during the first quarter of 2018, drilling three (3.0 net) multi-lateral horizontal heavy oil wells to develop the Birch General Petroleum A pool in the Mannville area. The three oil wells came on production in late March with one infill well producing at type curve expectations and two pool extension wells producing at lower rates than targeted.

- The remaining capital activity was primarily directed towards waterflood optimization and water handling with the conversion of one new injector, one new disposal well and pipeline construction and associated facilities for water management. The disposal facility is working well and the Company expects this to translate into future netback improvements. Pressure response is already apparent from the injector conversion, further validating the success of the Mannville waterfloods.

- Crude oil production in eastern Alberta was flat relative to the first quarter of 2017 and the immediately preceding fourth quarter of 2017 at 857 bbl/d, reflecting very low base decline rates driven by the strong waterflood response observed in several heavy oil pools.

- Gas production in eastern Alberta was 4.9 MMcf/d, down 25% from the comparative period of 2017, due to deferred spending on shallow gas recompletion activity given low natural gas prices as well as cold weather-related well freeze off incidents.

- Close to $0.4 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. Perpetual received six reclamation certificates related to asset retirement obligation spending in prior periods which enable reduced property tax and surface lease rental costs going forward.

- Production and operating expenses in eastern Alberta were $18.20/boe during the quarter (Q1 2017 – $14.34/boe; Q4 2017 – $12.63/boe). The first quarter of 2018 saw higher than average well servicing requirements in the Mannville heavy oil operations which increased operating costs as well as negatively affecting production volumes.

- Summer drilling plans include the drilling of two (1.3 net) wells, with a third development well planned late in the year if positive pressure response from the new injector continues.

Advance high impact opportunities

- Perpetual continued to evaluate the application of solvent technology with heat for bitumen extraction in the Bluesky formation at Panny, utilizing important learnings from the Company's cyclic heat stimulation ("CHS") test conducted in the fall of 2015 through to the second quarter of 2017. 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.

- Nearby offsets to Perpetual's Duvernay formation lands in the Waskahigan area have been drilled by competitors in early 2018 which will provide valuable information to assess future development potential and economic viability.

- Production monitoring continued on the two horizontal pilot wells drilled in Q1 2017 to advance the evaluation of the shallow shale gas play in the Viking and Colorado formations in eastern Alberta. The Company remains encouraged by the potential of horizontal development of the tight Viking formation but has reverted to an incremental spending model to technically advance the play through recompletion activities during this current period of depressed natural gas prices in Alberta.

Optimize balance sheet for growth

- 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 $0.7 million.

- Perpetual's 35,000 MMBtu/d, five-year term market diversification contract contributed $2.4 million of incremental revenue during the quarter and increased Perpetual's average natural gas price by $0.41/Mcf over the AECO Daily Index price. The market diversification contract is settled against daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) that generally track North American NYMEX prices and account for transportation costs back to AECO. A contract for an additional 5,000 MMBtu/d commenced April 1, 2018, bringing total volumes exposed to 40,000 MMBtu/d. These contracts effectively shift the sales point to a basket of five North American natural gas hub pricing points, diversifying the Company's natural gas price exposure from AECO. Based on the current forward market, 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 first quarter of 2018 was $9.1 million ($0.15/share), up 78% over the prior year period of $5.1 million ($0.09/share) due to increased production and lower cash costs, but partially offset by lower revenue per boe. Adjusted funds flow per boe was $7.94/boe in the first quarter of 2018, up 14% over the prior year period.

- During the first quarter of 2018, the market value of the Company's 1.67 million TOU shares declined, prompting the Company to voluntarily pay down the TOU share margin loan by $2.5 million to maintain the lending ratio at less than 55%. The repayment was funded from borrowings on the bank syndicated credit facility. At March 31, 2018, Perpetual has a $16.0 million TOU share margin loan outstanding secured by the Company's TOU shares that matures on July 31, 2018. Perpetual received initial dividend income of $0.1 million in March 2018, largely offsetting interest on the TOU share margin loan. The market value of TOU shares held at March 31, 2018 was $36.4 million ($21.85/share) compared to $38.0 million at December 31, 2017 ($22.78/share).

- Perpetual ended the first quarter of 2018 with total net debt of $115.1 million, up $9.1 million from December 31, 2017. The increase reflects first quarter capital expenditures and lower market value of the TOU share investment.

- As at March 31, 2018, 55% 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 first quarter of 2018 to 3.3 times at March 31, 2018 (December 31, 2017 – 3.4 times).

- On May 7, 2018, the Company's revolving bank debt Borrowing Limit was decreased from $65 million to $60 million, with the next Borrowing Limit redetermination scheduled on or prior to November 30, 2018.

- After giving effect to the Borrowing Limit reduction, and factoring in letters of credit issued for operational purposes, Perpetual had available liquidity of $29.6 million on March 31, 2018.

2018 OUTLOOK

Please refer to "Management's Discussion and Analysis – 2018 Outlook" on page 8 of this first quarter 2018 report.

Susan Riddell Rose

Susan Riddell Rose
President and Chief Executive Officer
May 8, 2018

Financial and Operating Highlights

($Cdn thousands except volume and per share amounts)	Three months ended March 31, 2018	2017	Change
Financial			
Oil and natural gas revenue	**23,340**	18,158	29%
Net loss	**(6,465)**	(14,172)	54%
Per share – basic and diluted[2]	**(0.11)**	(0.26)	58%
Cash flow from (used in) operating activities	**11,198**	(2,289)	589%
Adjusted funds flow[1]	**9,101**	5,110	78%
Per share[1][2]	**0.15**	0.09	67%
Total assets	**363,273**	389,739	(7%)
Revolving bank debt	**46,912**	–	100%
Term Loan, at principal amount	**45,000**	35,000	29%
TOU share margin loan, at principal amount	**15,990**	35,039	(54%)
Senior Notes, at principal amount	**32,490**	60,573	(46%)
TOU share investment	**(36,434)**	(49,440)	(26%)
Adjusted working capital deficiency (surplus)[1]	**11,101**	(16,714)	(166%)
Net debt[1]	**115,059**	64,458	79%
Net capital expenditures			
Capital expenditures	**14,897**	24,590	(39%)
Net payments on acquisitions and dispositions	**926**	163	468%
Net capital expenditures	**15,823**	24,753	(36%)
Common shares (thousands)[3]			
End of period	**59,847**	58,990	1%
Weighted average - basic and diluted	**59,345**	54,468	9%
Operating			
Daily average production			
Natural gas (*MMcf/d*)	**65.9**	40.7	62%
Oil (*bbl/d*)	**900**	877	3%
NGL (*bbl/d*)	**848**	479	77%
Total (*boe/d*)	**12,742**	8,143	56%
Average prices			
Realized natural gas price (*$/Mcf*)	**2.65**	5.04	(47%)
Realized oil price (*$/bbl*)	**48.31**	31.39	54%
Realized NGL price (*$/bbl*)	**57.61**	49.70	16%
Wells drilled – gross (net)			
Natural gas	**1 (1.0)**	6 (6.0)	
Oil	**3 (3.0)**	4 (3.3)	
Total	**4 (4.0)**	10 (9.3)	

(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 months ended March 31, 2018 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's condensed interim consolidated financial statements and accompanying notes for the three months ended March 31, 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 May 7, 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 involves a high degree of discretion. 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 disposition of the Shallow Gas Properties, which management considers to not be related to cash flow from operating activities. Restructuring costs include employee downsizing costs and surplus office lease obligations. Commencing with this MD&A, the Company no longer excludes 'exploration and evaluation – geological and geophysical costs' (Q1 2018 and 2017 – nil) 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 March 31,	
(*$ thousands, except per share and per boe amounts*)	**2018**	2017
Net cash flows from (used in) operating activities	**11,198**	(2,289)
Changes in non-cash working capital	**(2,396)**	6,308
Expenditures on decommissioning obligations	**553**	563
Change in gas over bitumen royalty financing	**(439)**	(816)
Payments of restructuring costs	**185**	1,344
Adjusted funds flow	**9,101**	5,110
Adjusted funds flow per share	**0.15**	0.09
Adjusted funds flow per boe	**7.94**	6.97

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.

($ thousands, except per boe amounts)	Three months ended March 31, **2018**	2017
Royalties	**3,063**	3,102
Production and operating	**4,772**	4,601
Transportation	**1,443**	1,015
General and administrative	**3,311**	3,101
Cash interest expense and income	**2,115**	1,897
Cash costs	**14,704**	13,716
Cash costs per boe	**12.82**	18.72

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 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, excluding foreign exchange contracts is used by management to calculate the Corporation's net realized commodity prices, taking into account monthly settlements on financial crude oil and natural gas forward sales, collars and basis differentials. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices, and as such, any related realized gains or losses are considered part of the Corporation's realized price.

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

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

FIRST QUARTER 2018 HIGHLIGHTS

In response to the material weakening of AECO forward natural gas prices as the first quarter of 2018 commenced, Perpetual announced on February 7, 2018, changes to its 2018 capital plan designed to preserve the value of its liquids-rich natural gas East Edson reserves by deferring additional 2018 development drilling at East Edson in West Central Alberta and accelerating spending on more economic heavy oil projects at Mannville in Eastern Alberta, resulting in a net reduction to the 2018 capital budget to $23 - $27 million. Capital spending for the first quarter of 2018 was $14.8 million, of which 60% was incurred at East Edson where one extended reach horizontal ("ERH") well was drilled and two wells were completed and tied-in to production. At Mannville, additional waterflood infrastructure was added and three heavy oil horizontal wells were drilled and tied-in to production.

Production averaged 12,742 boe/d in the first quarter of 2018, up 8% over the fourth quarter of 2017 and 56% over the first quarter of 2017 due to the completion and tie-in of the East Edson drilling program during the second half of 2017 and first quarter of 2018. Cash costs were $12.82/boe in the first quarter of 2018, down 31% 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.

Realized revenue per boe was $20.96/boe in the first quarter of 2018 compared to $25.80/boe in the prior year period, down 19% primarily due to the 23% reduction in the AECO Daily Index natural gas price from the comparable period. Natural gas comprised 86% of production on a boe basis in the first quarter of 2018 compared to 83% in the prior year period.

Net loss for the first quarter of 2018 was $6.5 million ($0.11/share), compared to a net loss of $14.2 million ($0.26/share) in the comparative period. The improvement from the prior year period reflected stronger operational and capital performance, including a 56% increase in production, a 31% reduction in cash costs per boe and a 9% reduction in depletion expense per boe, partially offset by a 19% decrease in realized revenue per boe related to lower commodity prices.

Cash flow from operating activities in the first quarter of 2018 was $11.2 million ($0.19/share) compared to cash flow used in operating activities in the prior year period of $2.3 million.

Adjusted funds flow in the first quarter of 2018 was $9.1 million ($0.15/share), up 78% over the prior year period of $5.1 million ($0.09/share) due to increased production and lower cash costs, and despite lower revenue per boe. Adjusted funds flow per boe was $7.94/boe in the first quarter of 2018, up 14% over the prior year period.

OUTLOOK

Perpetual has lowered its 2018 capital expenditure guidance from a range of $23 to 27 million provided in a press release dated February 7, 2018 ("Prior Guidance") to $21 to 25 million ($6 to 10 million for the remainder of 2018) and reduced its Mannville heavy oil drilling in the second half of 2018 to two wells (1.3 net) from the previous range of six to ten wells. 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. Capital spending plans at Mannville include $1.5 to $2.0 million to capture anticipated banked oil from waterflood operations. Decommissioning expenditures are anticipated to be $1.0 to $1.5 million for the remainder of 2018. 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, down from prior guidance of 11,500 boe/d due to lower natural gas production in the first quarter due to freeze offs and shut-ins and lower heavy oil production anticipated over the balance of the year due to reduced capital spending.

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.

Cash costs of $14.00 to $15.00/boe are anticipated compared to prior guidance of $13.00 to $14.00/boe, due to the impact of the forecasted decrease in production on unit costs. Royalty costs are expected to be moderately lower for the balance of 2018 than in the first quarter, consistent with lower AECO forward natural gas prices for the remainder of 2018. Other cash costs for the remainder of 2018 are expected to be comparable to first quarter expense levels.

Adjusted funds flow for 2018 is anticipated to be in the $25 to $28 million range ($16 to $19 million for the remainder of 2018), down from previous guidance of $34 to $37 million due to lower heavy oil production and modestly lower natural gas prices.

Guidance assumptions are as follows:

	Current Guidance	Prior Guidance
Exploration and development expenditures	**$21 - 25 million**	$23 - 27 million
2018 cash costs	**$14.00 - $15.00/boe**	$13.00 - 14.00/boe
2018 average daily production	**10,500 - 11,000 boe/d**	11,500 boe/d
2018 average production mix	**15% oil and NGL**	17% oil and NGL

Commodity price assumptions are consistent with current market price levels as follows:

	Current Guidance	Prior Guidance
2018 average NYMEX natural gas price	**US$2.86/MMBtu**	US$2.98/MMBtu
2018 average NYMEX to AECO basis differential	**(US$1.73)/MMBtu**	(US$1.77)/MMBtu
2018 average West Texas Intermediate ("WTI") oil price	**US$65.55/bbl**	US$63.54/bbl
2018 average Western Canadian Select ("WCS") differential	**(US$22.30)/bbl**	(US$23.83)/bbl
2018 average exchange rate	**US$1.00 = $1.277**	US$1.00 = $1.235

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 $105 – $110 million, consistent with prior guidance, based on the following assumptions:

- Net debt at March 31, 2018 of $115 million
- Adjusted funds flow for the remainder of 2018 of $16 to $19 million
- Capital spending for the remainder of 2018 of $6 to $10 million
- Decommissioning expenditures for the remainder of 2018 of $1.0 to $1.5 million
- Shallow gas property disposition – fixed marketing obligation payment of $7.6 million

On May 7, 2018, the revolving bank debt Borrowing Limit was decreased from $65 million to $60 million with the next Borrowing Limit redetermination scheduled on or prior to November 30, 2018. After giving effect to this Borrowing Limit reduction, Perpetual had available liquidity of $29.6 million. To improve liquidity, Perpetual plans to pursue additional asset sales in 2018 including the potential disposition of TOU shares.

FIRST QUARTER FINANCIAL AND OPERATING RESULTS

Capital expenditures

	Three months ended March 31,	
(*$ thousands*)	**2018**	2017
Exploration and development	**14,847**	24,563
Other	**50**	27
Capital expenditures	**14,897**	24,590
Acquisitions	**–**	208
Net payments (proceeds) on dispositions	**926**	(45)
Total	**15,823**	24,753

Exploration and development spending by area

	Three months ended March 31,	
(*$ thousands*)	**2018**	2017
West Central	**8,942**	18,525
Eastern Alberta	**5,905**	6,038
Total	**14,847**	24,563

Wells drilled by area

	Three months ended March 31,	
(gross/net)	**2018**	2017
West Central	**1/1.0**	5/5.0
Eastern Alberta	**3/3.0**	5/4.3
Total	**4/4.0**	10/9.3

Perpetual's exploration and development spending in the first quarter of 2018 totaled $14.8 million. Capital expenditures included drilling 4 (4.0 net) wells, comprised of one (1.0 net) horizontal natural gas well at Edson and 3 (3.0 net) horizontal heavy oil wells at Mannville.

Spending at the East Edson property in West Central represented 60% of total exploration and development expenditures in the first quarter of 2018. East Edson capital activity included the drilling of one (1.0 net) extended reach horizontal ("ERH") Wilrich well and 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.

Spending in Eastern Alberta consisted of a three well (3.0 net) multi-lateral horizontal drilling program in the Company's Mannville heavy oil property, one waterflood injector well conversion, one water disposal well conversion and associated facilities. The three oil wells came on production in March with one infill well producing at type curve expectations and two pool extension wells producing at lower rates than expected. The disposal facility is working well and the Company expects this to translate into future netback improvements. Pressure response is already apparent from the injector conversion completed in December of 2017, further validating the success of the Mannville waterfloods. Summer drilling plans include the drilling of two (1.3 net) wells targeting banked waterflood oil.

Dispositions

Proceeds (payments) on dispositions

	Three months ended March 31,	
(*$ thousands*)	**2018**	2017
Proceeds on dispositions of oil and gas properties	**3**	436
Proceeds on retained shallow gas marketing arrangements	**–**	538
Payments on fixed portion of retained shallow gas marketing arrangements	**(929)**	(929)
Net proceeds (payments) on dispositions	**(926)**	45

Gain (loss) on dispositions

	Three months ended March 31,			
(*$ thousands*)		**2018**		2017
Proceeds on dispositions of oil and gas properties	**$**	**3**	$	436
Property, plant and equipment sold, net of accumulated DD&A		**–**		(8)
Marketing arrangements related to shallow gas property disposition		**–**		538
Unrealized loss on retained shallow gas marketing arrangements		**(874)**		(3,157)
Loss on dispositions	**$**	**(871)**	$	(2,191)

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 "Shallow Gas Disposition"). The Company entered into marketing arrangements prior to closing to fix the cost of the floor price protection through to March 31, 2018. During the three months ended March 31, 2018 and 2017, payments of $0.9 million respectively, were recorded as a reduction of this liability. 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 (used in) investing activities on the consolidated statement of cash flows.

During the three months ended March 31, 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 (Q1 2017 – $3.2 million). Realized gains of $0.5 million were recorded during the first quarter of 2017, reflecting cash proceeds received where AECO monthly prices exceeded $2.81/GJ on 33,611 GJ/d.

As at March 31, 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)***
April 2018 – August 2018	33,611	–	2.81	–
April 2018 – August 2018	33,611	2.58	–	(7,610)

Expenditures on decommissioning obligations

During the three months ended March 31, 2018, Perpetual spent $0.6 million (Q1 2017 – $0.6 million) on abandonment and reclamation projects. As part of Perpetual's focus on well and pipeline abandonment and reclamation, eight reclamation certificates were received from the Alberta Energy Regulator (Q1 2017 – 27 reclamation certificates) which will result in the cessation of associated property tax and surface lease expense. 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 months ended March 31, 2018 and 2017:

	Three months ended March 31, 2018			Three months ended March 31, 2017		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue[1]	**18,989**	**4,351**	**23,340**	13,052	5,106	18,158
Realized gains on derivatives[2]	**–**	**–**	**691**	–	–	747
Royalties	**(2,579)**	**(484)**	**(3,063)**	(2,694)	(408)	(3,102)
Production and operating expenses	**(2,043)**	**(2,729)**	**(4,772)**	(2,093)	(2,508)	(4,601)
Transportation costs	**(1,128)**	**(315)**	**(1,443)**	(602)	(413)	(1,015)
Total operating netback	**13,239**	**823**	**14,753**	7,663	1,777	10,187

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

	Three months ended March 31, 2018			Three months ended March 31, 2017		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Boe operating netback						
Production *(boe/d)*	**11,076**	**1,666**	**12,742**	6,199	1,944	8,143
Total petroleum and natural gas revenue	**19.05**	**29.02**	**20.36**	23.39	29.19	24.78
Realized gains on derivatives	**–**	**–**	**0.60**	–	–	1.02
Royalties	**(2.59)**	**(3.23)**	**(2.67)**	(4.83)	(2.33)	(4.23)
Production and operating expenses	**(2.05)**	**(18.20)**	**(4.16)**	(3.75)	(14.34)	(6.28)
Transportation costs	**(1.13)**	**(2.10)**	**(1.26)**	(1.08)	(2.36)	(1.38)
Total operating netback	**13.28**	**5.49**	**12.87**	13.73	10.16	13.91

Perpetual's operating netback of $14.8 million ($12.87/boe) in the first quarter of 2018 increased 45% from $10.2 million ($13.91/boe) in the comparative period of 2017. This increase was due to the 56% increase in production, partially offset by a 7% reduction in operating netback per boe. The decrease in operating netback per boe for the first quarter of 2018 compared to the prior year period reflects an 18% reduction in total petroleum and natural gas revenue per boe due principally to the 23% decrease in the Alberta Daily Index natural gas price. This was partially offset by a 37% decrease in royalties per boe along with a 34% reduction in operating expenses per boe, driven by a 45% reduction in West Central operating costs to $2.05/boe.

Production

	Three months ended March 31, 2018	2017
Natural gas (*MMcf/d*)		
Eastern Alberta	**4.9**	6.5
West Central	**61.0**	34.2
Total natural gas[(1)]	**65.9**	40.7
Crude oil (*bbl/d*)		
Eastern Alberta[(2)]	**857**	859
West Central	**43**	18
Total crude oil	**900**	877
Total NGL (*bbl/d*)[(3)]	**848**	479
Total production (*boe/d*)	**12,742**	8,143

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

First quarter production averaged 12,742 boe/d, up 8% from the fourth quarter of 2017 and 56% from 8,143 boe/d produced in the prior year period reflecting a 79% increase in natural gas and associated NGL production at East Edson, driven by the 2017 and Q1 2018 capital program. First quarter production was 4% below prior guidance due to weather related well freeze off incidents and temporary production constraints experienced during drilling and completion operations at East Edson. 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. Heavy oil production in Eastern Alberta was maintained at 2017 first quarter levels as positive waterflood response in several pools restored pressure support and offset production declines. Production increases from wells drilled and tied in were not impactful on the first quarter of 2018 as the wells were brought on production at the end of the quarter.

Commodity Prices

	Three months ended March 31, 2018	2017
Reference prices		
NYMEX Daily Index (*US$/MMBtu*)	**3.00**	3.32
AECO Daily Index (*$/GJ*)	**1.97**	2.55
AECO Daily Index (*$/Mcf*)[(1)]	**2.08**	2.69
Alberta Gas Reference Price (*$/GJ*)[(2)]	**1.68**	2.48
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**62.87**	51.92
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(24.28)**	(14.57)
WCS average (*$CAD/bbl*)[(4)]	**48.63**	49.29
Average Perpetual prices		
Natural gas (*$/Mcf*)[(1)]		
AECO Daily Index	**2.08**	2.69
Heat content premium[(3)]	**0.23**	0.27
Market diversification contracts	**0.41**	–
Realized gains (losses) on financial and physical gas derivatives	**(0.08)**	1.92
Realized gains (losses) on prompt month price optimization	**0.01**	0.16
Realized natural gas price (*$/Mcf*)[(5)]	**2.65**	5.04
Percent of AECO Daily Index	**127**	187
Realized oil price (*$/bbl*)[(5)]	**48.31**	31.39
Realized natural gas liquids ("NGL") price (*$/bbl*)	**57.61**	49.70

(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) Realized natural gas prices are at a premium to the AECO Daily Index due to higher heat content. For the period ended March 31, 2018, Perpetual received an 11% premium to the AECO Daily Index (Q1 2017 – 10%).
(4) Derived internally using the Bank of Canada average foreign exchange rate of US$1.00 = $1.26 for the three months ended March 31, 2018 (Q1 2017 – $1.32).
(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. Realized gains and losses from foreign exchange contracts are excluded.

Despite a colder year-over-year winter, higher North American production caused NYMEX natural gas prices to decrease 10% from US$3.32/MMBtu for Q1 2017 to an average of US$3.00/MMBtu for Q1 2018. In comparison, the AECO Daily Index prices decreased 23% from $2.55/GJ in Q1 2017 to $1.97/GJ in Q1 2018. In mid-2017, AECO became disconnected from the North American market as production growth in the Western Canadian Sedimentary Basin has outpaced access to markets outside of Western Canada and market demand.

The increase of WTI to US$62.87/bbl for Q1 2018 from US$51.92/bbl for Q1 2017 was related to the gradual reduction in global oil inventories during 2017 and into 2018 as a result of increased global demand of crude and the supply restrictions implemented by OPEC effective January 1, 2017 to the extent of 1.2 million bbl/d along with an additional cut from select non-OPEC producers of up to 0.6 million bbl/d. The WCS differential increased from an average US$14.57/bbl in the first quarter of 2017 to US$24.28/bbl in the current quarter due to increased heavy oil and bitumen production in Western Canada combined with pipeline capacity constraints that has restricted access to markets outside of Western Canada.

Perpetual's realized natural gas price, including derivatives, decreased 47% to $2.65/Mcf for the first quarter ended March 31, 2018 from $5.04/Mcf in the first quarter of 2017, representing 127% of the AECO Daily Index price compared to 187% in the prior year period. Realized losses on financial and physical gas derivatives, along with prompt month price optimization operations deducted $0.07/Mcf from the realized price in the first quarter of 2018 (Q1 2017 – $2.08/Mcf gain), while the 35,000 MMBtu/d market diversification contract sales that are related to NYMEX daily index prices added $0.41/Mcf (Q1 2017 – nil). During the first 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 first quarter 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. Effective April 1, 2018, market diversification contract sales increased to 40,000 MMBtu/d.

Perpetual's realized oil price of $48.31/bbl was 54% higher than the first quarter of 2017 and included realized gains on crude oil derivative contracts of $0.4 million ($5.23/bbl). Realized prices in the first quarter of 2017 were reduced by $12.34/bbl associated with realized hedging losses in the period.

Perpetual's realized NGL price for the first quarter of 2018 reached $57.61/bbl, up 16% from the first quarter of 2017, reflecting an increase in all NGL component prices. Perpetual's average NGL sales composition for the first quarter ended March 31, 2018 consisted of 63% condensate, a slight decrease from the prior year period (Q1 2017 – 67%).

Revenue

	Three months ended March 31,	
($ thousands, except as noted)	**2018**	2017
Petroleum and natural gas revenue		
Natural gas[(1)]	**15,451**	12,563
Oil[(1)]	**3,490**	3,451
NGL	**4,399**	2,144
Total petroleum and natural gas revenue	**23,340**	18,158
Realized gains (losses) on derivatives[(2)]	**691**	747
Realized revenue	**24,031**	18,905
Unrealized gains (losses) on derivatives	**(2,326)**	3,246
Total revenue	**21,705**	22,151
Realized revenue *($/boe)*	**20.96**	25.80
Total revenue *($/boe)*	**18.93**	30.23

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

Perpetual's petroleum and natural gas ("P&NG") revenue, before derivatives, for the three months ended March 31, 2018 of $23.3 million increased 29% from the first quarter of 2017 due to a 56% increase in average daily production, partially offset by lower natural gas prices. Natural gas revenue, before derivatives, of $15.5 million in the first quarter of 2018 comprised 66% (Q1 2017 – 69%) of total petroleum and natural gas revenue and 86% (Q1 2017 – 83%) of production. Natural gas revenue increased 23% from $12.6 million in 2017 reflecting the impact of the 62% increase in production volumes driven by the 2017 and Q1 2018 East Edson capital program, partially offset by lower AECO natural gas prices. Perpetual's 35,000 MMBtu/d, five-year term market diversification contract contributed $2.4 million of incremental revenue and increased Perpetual's average realized natural gas price by $0.41/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.

First quarter 2018 oil revenue of $3.5 million represented 15% (Q1 2017 – 19%) of total petroleum and natural gas revenue while oil production was 7% (Q1 2017 – 11%) of total production. Oil revenue was comparable to the same period in 2017 due to similar production levels and WCS average prices as increases in the WTI US$ benchmark price was fully offset by the higher WCS differential and a stronger Canadian dollar compared to the prior year period.

NGL revenue for the first quarter of 2018 of $4.4 million represented 19% (Q1 2017 – 12%) of total petroleum and natural gas revenue while NGL production was just 7% (Q1 2017 – 6%) of total Company production. NGL revenue increased by 105% over the prior year period as production increased by 77% tracking increased natural gas production at East Edson, combined with a 16% increase in NGL prices compared to the prior year period, closely correlated to the increase in WTI light oil prices.

Realized gains on derivatives totaled $0.7 million for the first quarter of 2018, comparable to gains of $0.7 million in 2017. Total gains in the current period were comprised of $0.3 million on natural gas derivatives and $0.4 million from oil derivatives.

Perpetual recorded unrealized losses on derivatives of $2.3 million during the first three months of 2018 compared to unrealized gains of $3.2 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 March 31, 2018	2017
Crown	**801**	478
Freehold and overriding[1]	**2,262**	2,624
Total	**3,063**	3,102
Crown (*% of P&NG revenue*)	**3.4**	2.6
Freehold and overriding (*% of P&NG revenue*)	**9.7**	14.5
Total (*% of P&NG revenue*)	**13.1**	17.1
$/boe	**2.67**	4.23

(1) Includes $1.6 million in gross overriding royalty payments at East Edson for the three months ended March 31, 2018 (Q1 2017 – $2.0 million).

Royalty expenses for the quarter ended March 31, 2018 were $3.1 million, comparable to the first quarter 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 17.1% in the prior year period to 13.1% in the first quarter of 2018 due mainly to a lower effective freehold and overriding royalty rate at East Edson. 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 production has increased by 79% in the first 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 March 31, 2018	2017
Production and operating expenses	**4,772**	4,601
$/boe	**4.16**	6.28

Total production and operating expenses were down 34% on a unit-of-production basis to $4.16/boe for the first quarter of 2018, but comparable on an absolute dollar basis to the prior year period despite the 56% increase in production over the comparable period. Increased production at East Edson combined with a low variable cost structure, drove West Central operating costs down to $2.05/boe in the first quarter of 2018 (Q1 2017 – $3.75/boe). The first quarter of 2018 saw higher than average well servicing requirements in the Mannville heavy oil operations which increased operating costs as well as negatively affecting production volumes.

Transportation costs

($ thousands, except as noted)	Three months ended March 31, 2018	2017
Transportation costs	**1,443**	1,015
$/boe	**1.26**	1.38

Transportation costs include clean oil trucking and NGL transportation as well as costs to transport natural gas from the plant gate to commercial sales points. Transportation costs in the first quarter of 2018 were $1.4 million, up 42% from the prior year period due to increased production from West Central where transportation costs averaged $1.13/boe compared to $2.10/boe for production from Eastern Alberta. Transportation costs were $1.26/boe in the first quarter, down 9% from the prior year period largely due to a higher percentage of production from the low transportation cost West Central properties.

Gas over bitumen

($ thousands, except as noted)	Three months ended March 31, 2018	2017
Gas over bitumen royalty credit	**383**	925
Payments on gas over bitumen royalty financing[1]	**(439)**	(816)
Gas over bitumen revenue, net of payments	**(56)**	109
$/boe	**(0.05)**	0.15

(1) At March 31, 2018, the fair value of the gas over bitumen royalty financing was estimated to be $2.2 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 three months ended March 31, 2018, Perpetual recorded $0.4 million in gas over bitumen revenue; a decrease of $0.5 million (59%) from the same period in 2017 attributable to the 32% reduction in Alberta gas reference prices, combined with the annual 10% decline in deemed production.

Gas over bitumen royalty credits earned in the first quarter of 2018 funded payments of $0.4 million (Q1 2017 – $0.8 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 separately as a reduction to the gas over bitumen royalty financing obligation. For purposes of this MD&A, the monthly payments have been included as a reduction to gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty adjustments. During the first quarter of 2018, the gas over bitumen royalty financing obligation was reduced by $0.6 million, comprised of payments of $0.4 million and an unrealized gain of $0.2 million. The gain has been included in non-cash finance expense and represents a decrease in the fair value of the gas over bitumen royalty financing obligation as a result of lower forecasted natural gas reference prices.

Exploration and evaluation

	Three months ended March 31,	
(*$ thousands*)	**2018**	2017
Lease rentals	**170**	188
Geological and geophysical costs	**–**	–
Lease expiries (non-cash)	**–**	1,313
Total exploration and evaluation	**170**	1,501

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. E&E costs of $0.2 million during the three months ended March 31, 2018 were comprised of lease rentals that were comparable to the prior year period. The first quarter of 2017 included $1.3 million of non-cash write-downs associated with lease expiries combined with certain leases deemed to no longer be part of Perpetual's future development plans.

General and administrative ("G&A") expenses

	Three months ended March 31,	
(*$ thousands, except as noted*)	**2018**	2017
Cash G&A expense	**3,914**	4,205
Overhead recoveries	**(603)**	(1,104)
Total G&A expense	**3,311**	3,101
$/boe	**2.89**	4.23

Cash G&A expense decreased 7% to $3.9 million in 2018 from $4.2 million in the comparative period. This decrease reflected reductions in office lease costs, staffing levels and diligent expense management. Overhead recoveries decreased in the first quarter of 2018 by $0.5 million (45%), consistent with the reduction in capital spending compared to the prior year period. Total G&A expense was $2.89/boe in the first quarter of 2018, down 32% from the prior year period due to increased production.

Share-based payments

	Three months ended March 31,	
(*$ thousands, except as noted*)	**2018**	2017
Share-based payments expense (non-cash)	**806**	1,532
$/boe	**0.70**	2.09

Non-cash share-based payments expense for the three months ended March 31, 2018 was $0.8 million, down $0.7 million compared to the same period in 2017 due to a reduction in the value of share-based compensation grants made during the period.

Depletion and depreciation

	Three months ended March 31,	
(*$ thousands, except as noted*)	**2018**	2017
Depletion and depreciation	**10,124**	7,125
$/boe	**8.83**	9.72

Perpetual recorded $10.1 million of depletion and depreciation expense for the three months ended March 31, 2018, an increase of 42% over $7.1 million recorded in the prior year period. The increase in expense reflects the 56% increase in production compared to the prior year period, partially offset by a 9% reduction in the depletion rate reflecting the success of the Company's 2017 capital expenditure program that added proved plus probable reserves at a cost of $5.98/boe.

Finance expenses

($ thousands)	Three months ended March 31, 2018	2017
Cash interest expense and income		
Interest on revolving bank debt	**468**	180
Interest on TOU share margin loan	**148**	214
Interest on Term Loan	**911**	145
Interest on Senior Notes	**721**	1,358
Dividend income from TOU share investment	**(133)**	–
Total cash interest expense and income	**2,115**	1,897
Non-cash finance expense		
Amortization of debt issue costs	**250**	94
Accretion on decommissioning obligations	**207**	191
Change in fair value of gas over bitumen royalty financing	**(130)**	(1,239)
Change in fair value of TOU share put option margin loans	**–**	921
Total non-cash finance expense	**327**	(33)
Finance expenses recognized in net loss	**2,442**	1,864

Total cash interest expense and income of $2.1 million for the three months ended March 31, 2018 was 11% higher than the prior year period ($1.9 million) due to increased debt levels compared to the prior year period, partially offset by the initial dividend income of $0.1 million received from the TOU share investment during the first quarter of 2018.

Total non-cash finance expenses for the three months ended March 31, 2018 were $0.3 million (Q1 2017 – nil). A reduction in the fair value of the gas over bitumen royalty financing was recorded in both periods due to lower AECO future natural gas prices and now stands at $2.2 million. The $0.9 million reduction in the fair value of TOU share put option margin loans recorded in the first quarter of 2017 did not re-occur in the first 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 March 31, 2018, Perpetual recorded an unrealized loss related to its TOU share investment of $1.6 million (Q1 2017 – $11.2 million) driven by the change in fair value of TOU shares from $22.78/share at December 31, 2017 to $21.85/share at March 31, 2018. During the first quarter of 2017, 180,000 TOU shares were sold at $31.63/share for net cash proceeds of $5.7 million. At March 31, 2018 and 2017, the Company owned 1.67 million TOU shares.

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. 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 and longer term financial sustainability.

Capital Management

(*$ thousands, except as noted*)	**March 31, 2018**	December 31, 2017
Revolving bank debt	**46,912**	31,581
Term Loan, measured at principal amount	**45,000**	45,000
TOU share margin loan, measured at principal amount	**15,990**	18,490
Senior Notes, measured at principal amount	**32,490**	32,490
TOU share investment(1)	**(36,434)**	(37,985)
Net working capital deficiency(2)	**11,101**	16,404
Net debt(2)	**115,059**	105,980
Shares outstanding at end of period (*thousands*)(3)	**59,847**	59,263
Market price at end of period (*$/share*)	**0.80**	1.10
Market value of shares	**47,878**	65,189
Enterprise value(2)	**162,937**	171,169
Net debt as a percentage of enterprise value	**71**	62
Trailing twelve months adjusted funds flow(2)	**35,106**	31,115
Net debt to trailing twelve months adjusted funds flow	**3.3 times**	3.4 times

(1) The TOU share investment is based on the March 31, 2018 closing price per the Toronto Stock Exchange ($21.85 per share) and 1.67 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 March 31, 2018, Perpetual had total net debt of $115.1 million, up $9.1 million from December 31, 2017. The increase reflects the first quarter capital expenditures and lower market value of the TOU share investment, partially offset by the reduction of the net working capital deficiency.

As at March 31, 2018, 55% 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 first quarter of 2018 to 3.3 times at March 31, 2018 (December 31, 2017 – 3.4 times).

On May 7, 2018, the revolving bank debt Borrowing Limit was decreased from $65 million to $60 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. After giving effect to this Borrowing Limit reduction, Perpetual had available liquidity of $29.6 million.

TOU share margin loan

At March 31, 2018, Perpetual had a $15.9 million TOU share margin loan ($16.0 million principal amount) secured by 1.67 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 March 31, 2018, the TOU share price declined in value, prompting the Company to voluntarily pay down the TOU share margin loan by $2.5 million to maintain the Lending Ratio at less than 55%, funded from borrowings on its Credit Facility. As at March 31, 2018, the Lending Ratio was 44% of the closing market value of the pledged TOU shares. The TOU share margin loan is designated as a financial liability measured at amortized cost.

The effective interest rate on the TOU share margin loan as at March 31, 2018 was 4.0%. For the period ended March 31, 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 March 31, 2018.

Revolving Bank Debt

As at March 31, 2018, the Company's reserve-based revolving credit facility (the "Credit Facility") had a borrowing limit (the "Borrowing Limit") of $65 million (December 31, 2017 – $65.0 million) under which $46.9 million was drawn (December 31, 2017 – $31.6 million) and $3.9 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 revolving bank debt Borrowing Limit was decreased from $65 million to $60 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.

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 March 31, 2018 was 4.6%. For the period ended March 31, 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 $0.5 million (Q1 2017 – nil).

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

Term Loan

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

($ thousands)	**March 31, 2018**	December 31, 2017
Balance, beginning of period	**$ 43,233**	$ –
Principal amount of Term Loan issued	**–**	45,000
Value allocated to warrants issued	**–**	(769)
Issue costs	**–**	(1,361)
Amortization of issue costs	**120**	363
Balance, end of period	**$ 43,353**	$ 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 March 31, 2018, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior Notes

			March 31, 2018		December 31, 2017	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 Senior Notes	July 23, 2019	8.75%	**14,572**	**14,491**	14,572	14,476
2022 Senior Notes	January 23, 2022	8.75%[1]	**17,918**	**17,228**	17,918	17,204
			$ 32,490	**$ 31,719**	$ 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 9.75% until January 23, 2018 and 8.75% thereafter 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 March 31, 2018 the Senior Notes are presented net of $0.8 million in issue costs which are amortized using a weighted average effective interest rate of 9.6%.

At March 31, 2018, in addition to the restricted payment covenants noted above, the Senior Notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Equity

At March 31, 2018 there were 59.8 million common shares outstanding, net of 0.3 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended March 31, 2018 were 59.3 million (March 31, 2017 – 54.5 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 commons shares and 0.4 million warrants for proceeds of $2.9 million.

At May 7, 2018 there were 59.6 million common shares outstanding which is net of 0.6 million shares held in trust for employee compensation programs.

SUMMARY OF QUARTERLY RESULTS

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

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

(*$ thousands, except as noted*)	Q1 2017	Q4 2016	Q3 2016	Q2 2016
Financial				
Oil and natural gas revenues	18,158	17,940	22,268	16,501
Net income (loss)	(14,172)	20,379	(10,919)	64,925
Per share – basic	(0.26)	0.39	(0.21)	1.25
Per share – diluted	(0.26)	0.37	(0.21)	1.23
Cash flow from (used in) operating activities	(2,289)	4,740	(1,710)	(3,396)
Adjusted funds flow(1)	5,110	3,329	(602)	(1,863)
Per share – basic	0.09	0.06	(0.01)	(0.04)
Net capital expenditures				
Exploration and development and other	24,590	7,069	1,411	1,286
Net payments (proceeds) on acquisitions and dispositions	163	1,785	(988)	(302)
Net capital expenditures	24,753	8,854	423	984
Common shares (*thousands*)(2)				
Weighted average – basic	54,468	52,924	52,253	52,140
Weighted average – diluted	54,468	54,678	52,253	52,904
Operating				
Daily average production				
Natural gas (*MMcf/d*)	40.7	40.3	75.5	85.2
Oil (*bbl/d*)	877	936	1,052	1,073
NGL (*bbl/d*)	479	467	476	682
Total (*boe/d*)	8,143	8,118	14,123	15,959
Average prices				
Realized natural gas price (*$/Mcf*)	5.04	2.41	2.12	1.85
Realized oil price (*$/bbl*)	31.39	38.95	38.90	39.17
NGL price (*$/bbl*)	49.70	46.99	35.80	34.71

(1) See "Non-GAAP measures" in this MD&A.
(2) Common shares and per share amounts have been retroactively adjusted to reflect the consolidation of outstanding common shares on the basis of 20 common shares to one common share on March 24, 2016. All common shares are net of shares held in trust.

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 management contracts outstanding at May 7, 2018:

Natural Gas

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

Term	Volumes sold (bought) at AECO (*GJ/d*)	Average price (*$/GJ*)(1)	Market prices (*$/GJ*)(2)	Type of contract
April 2018 – October 2018	10,000	2.06	1.01	Financial
April 2018 – March 2019	10,000	1.41	1.35	Financial
September 2018 – March 2019	5,000	1.40	1.63	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for April and May 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 May 7, 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
June 2018 – October 2018	5,000	(1.87)	(1.96)	Financial
January 2019 – December 2019	12,500	(1.54)	(1.48)	Physical
January 2019 – December 2019	7,500	(1.50)	(1.48)	Financial
January 2020 – December 2020	12,500	(1.41)	(1.42)	Physical
January 2020 – December 2020	15,000	(1.41)	(1.42)	Financial
January 2021 – December 2021	5,000	(1.15)	(1.17)	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for April and May 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 May 7, 2018.

Crude Oil

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

Term	Volumes (*bbl/d*)	Floor price (*US$/bbl*)	Ceiling price (*US$/bbl*)	Market prices (*US$/bbl*)(1)	Type of contract
April 2018 – December 2018	250	50.00	58.40	68.90	Financial
April 2018 – December 2018	250	50.00	60.00	68.90	Financial

(1) Market prices for April are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on May 7, 2018.

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
April 2018 – December 2018	250	63.74	68.90	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for April are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on May 7, 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
April 2018 – June 2018	500	(14.45)	(20.32)	Financial
July 2018	500	(19.75)	(21.08)	Financial

(1) Average price calculated using weighted average price for net open contracts; contracts settle at WTI index less a fixed basis amount.
(2) Market prices for April and May 2018 are based on settled WTI-WCS differential prices. Market prices for subsequent months are based on forward WTI-WCS differential prices as of market close on May 7, 2018.

Natural Gas Sales Obligations

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**

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 quantitative impact of the adoption of IFRS 16 is currently being evaluated.

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 March 31, 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		**March 31, 2018**		December 31, 2017
(*Cdn$ thousands unaudited*)				
Assets				
Current assets				
Accounts receivable	**$**	**9,496**	$	14,069
Tourmaline Oil Corp. ("TOU") share investment (note 3)		**36,434**		37,985
Prepaid expenses and deposits		**722**		937
Fair value of derivatives (note 16)		**1,875**		1,585
		48,527		54,576
Fair value of derivatives (note 16)		**207**		1,506
Property, plant and equipment (note 4)		**267,715**		262,784
Exploration and evaluation (note 5)		**46,824**		46,704
Total assets	**$**	**363,273**	$	365,570
Liabilities				
Current liabilities				
Accounts payable and accrued liabilities	**$**	**21,319**	$	31,410
Fair value of derivatives (note 16)		**9,028**		7,885
TOU share margin loan (note 7)		**15,929**		18,406
Gas over bitumen royalty financing		**992**		1,152
Provisions (note 11)		**1,792**		2,580
		49,060		61,433
Fair value of derivatives (note 16)		**119**		–
Revolving bank debt (note 8)		**46,912**		31,581
Term loan (note 9)		**43,353**		43,233
Senior notes (note 10)		**31,719**		31,680
Gas over bitumen royalty financing		**1,178**		1,587
Provisions (note 11)		**36,640**		36,105
Total liabilities		**208,981**		205,619
Equity				
Share capital (note 12)		**1,337,961**		1,336,838
Warrants (note 12)		**923**		923
Contributed surplus		**43,835**		44,152
Deficit		**(1,228,427)**		(1,221,962)
Total equity		**154,292**		159,951
Total liabilities and equity	**$**	**363,273**	$	365,570

Subsequent event (note 8).

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

	Three months ended March 31, 2018	2017
(*Cdn$ thousands, except per share amounts unaudited*)		
Revenue		
Oil and natural gas (note 14)	**$ 23,340**	$ 18,158
Royalties	**(3,063)**	(3,102)
	20,277	15,056
Change in fair value of derivatives (note 16)	**(1,635)**	3,993
Gas over bitumen royalty credit and other	**383**	925
	19,025	19,974
Expenses		
Production and operating	**4,772**	4,601
Transportation	**1,443**	1,015
Exploration and evaluation (note 5)	**170**	1,501
General and administrative	**3,311**	3,101
Share-based payments (note 13)	**806**	1,532
Loss on dispositions (note 4a)	**871**	2,191
Depletion and depreciation (note 4)	**10,124**	7,125
Loss from operating activities	**(2,472)**	(1,092)
Finance expenses (note 15)	**(2,442)**	(1,864)
Change in fair value of TOU share investment (note 3)	**(1,551)**	(11,216)
Net loss and comprehensive loss	**(6,465)**	(14,172)
Loss per share (note 12)		
Basic	**$ (0.11)**	$ (0.26)
Diluted	**$ (0.11)**	$ (0.26)

See accompanying notes to the condensed interim consolidated financial statements.

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

	Share capital			Contributed		
	(thousands)	*($thousands)*	Warrants	surplus	Deficit	Total equity
(Cdn$ thousands unaudited)						
Balance at December 31, 2017	59,263	$ 1,336,838	$ 923	$ 44,152	$ (1,221,962)	$ 159,951
Net loss	–	–	–	–	(6,465)	(6,465)
Common shares issued (note 12)	472	905	–	(905)	–	–
Change in shares held in trust	112	218	–	(218)	–	–
Share-based payments	–	–	–	806	–	806
Balance at March 31, 2018	**59,847**	**$1,337,961**	**$ 923**	**$ 43,835**	**$ (1,228,427)**	**$ 154,292**

	Share capital			Contributed		
	(thousands)	*($thousands)*	Warrants	surplus	Deficit	Total equity
(Cdn$ thousands unaudited)						
Balance at December 31, 2016	53,421	$ 1,325,705	$ –	$ 42,999	$ (1,185,991)	$ 182,713
Net loss	–	–	–	–	(14,172)	(14,172)
Common shares and warrants issued (note 12)	5,569	9,892	923	(1,101)	–	9,714
Share-based payments	–	–	–	1,532	–	1,532
Balance at March 31, 2017	**58,990**	**$ 1,335,597**	**$ 923**	**$ 43,430**	**$ (1,200,163)**	**$ 179,787**

See accompanying notes to the condensed interim consolidated financial statements.

PERPETUAL ENERGY INC.
Condensed Interim Consolidated Statements of Cash Flows

	Three months ended March 31,	
	2018	2017
(*Cdn$ thousands unaudited*)		
Cash flows from (used in) operating activities		
Net loss	**$ (6,465)**	$ (14,172)
Adjustments to add (deduct) non-cash items:		
Depletion and depreciation (note 4)	**10,124**	7,125
Exploration and evaluation (note 5)	**–**	1,313
Share-based payments	**806**	1,532
Unrealized change in fair value of derivatives (note 16)	**2,326**	(3,246)
Change in fair value of TOU share investment (note 3)	**1,551**	11,216
Loss on dispositions (note 4a)	**871**	2,191
Finance expenses (income) (note 15)	**327**	(33)
Expenditures on decommissioning obligations (note 11)	**(553)**	(563)
Payments of restructuring costs (note 11b)	**(185)**	(1,344)
Change in non-cash working capital	**2,396**	(6,308)
Net cash flows from (used in) operating activities	**11,198**	(2,289)
Cash flows from (used in) financing activities		
Change in revolving bank debt, net of issue costs	**15,286**	–
Change in TOU share margin loan, net of issue costs (note 7)	**(2,523)**	(5,835)
Change in term loan, net of issue costs (note 9)	**–**	33,728
Change in senior notes, net of issue costs	**–**	(344)
Change in gas over bitumen royalty financing	**(439)**	(816)
Common shares and warrants issued (note 12)	**–**	8,945
Change in non-cash working capital	**–**	(216)
Net cash flows from financing activities	**12,324**	35,462
Cash flows from (used in) investing activities		
Capital expenditures	**(14,897)**	(24,590)
Acquisitions	**–**	(208)
Net proceeds (payments) on dispositions (note 4a)	**(926)**	45
Proceeds on sale of TOU share investment (note 3)	**–**	5,687
Restricted cash	**–**	2,000
Change in non-cash working capital	**(7,699)**	19,247
Net cash flows from (used in) investing activities	**(23,522)**	2,181
Change in cash and cash equivalents	**–**	35,354
Cash and cash equivalents, beginning of period	**–**	2,877
Cash and cash equivalents, end of period	**$ –**	$ 38,231

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 months ended March 31, 2018 are comprised of the accounts of the Company 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 judgments 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 May 7, 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. As at March 31, 2018, the Company did not have any trade accounts receivable that were outstanding for more than 60 days. The average expected credit loss on the Company's trade accounts receivable was not significant as at March 31, 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 reasonable 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 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.

3. TOU SHARE INVESTMENT

	March 31, 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	**–**	**–**	(180)	(5,687)
Unrealized change in fair value	**–**	**(1,551)**	–	(22,671)
Balance, end of period	**1,667**	**$ 36,434**	1,667	$ 37,985

At March 31, 2018, the Company held 1.67 million (December 31, 2017 – 1.67 million) TOU shares with a fair value of $36.4 million (December 31, 2017 – $38.0 million) based on a March 31, 2018 closing price of $21.85 per share (December 31, 2017 – $22.78 per share). Net income for the three months ended March 31, 2018 included an unrealized loss of $1.6 million (Q1 2017 – $11.2 million unrealized loss) representing the change in fair value of TOU shares held during the period.

At March 31, 2018, 1.67 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 March 31, 2018, a $1.00 per share change in the market price of TOU shares would change the Company's net income (loss) by $1.7 million.

4. PROPERTY, PLANT AND EQUIPMENT

	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	14,727	50	14,777
Change in decommissioning obligations (note 11)	278	–	278
March 31, 2018	**$ 702,306**	**$ 7,311**	**$ 709,617**
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	(10,101)	(23)	(10,124)
March 31, 2018	**$ (434,766)**	**$ (7,136)**	**$ (441,902)**
Carrying amount			
December 31, 2017	$ 262,636	$ 148	$ 262,784
March 31, 2018	**$ 267,540**	**$ 175**	**$ 267,715**

At March 31, 2018, property, plant and equipment included $1.6 million (December 31, 2017 – $1.3 million) of costs currently not subject to depletion.

a) Dispositions

Proceeds (payments) on dispositions

	Three months ended March 31,	
	2018	2017
Proceeds on dispositions of oil and gas properties	**3**	436
Proceeds on retained shallow gas marketing arrangements	**–**	538
Payments on fixed portion of retained shallow gas marketing arrangements	**(929)**	(929)
Net proceeds (payments) on dispositions	**(926)**	45

Gain (loss) on dispositions

	Three months ended March 31, **2018**	2017
Proceeds on dispositions of oil and gas properties	**$ 3**	$ 436
Property, plant and equipment sold, net of accumulated DD&A	**–**	(8)
Marketing arrangements related to shallow gas property disposition	**–**	538
Unrealized loss on retained shallow gas marketing arrangements	**(874)**	(3,157)
Loss on dispositions	**$ (871)**	$ (2,191)

Dispositions of oil and gas properties during the first quarter of 2018 were nominal, while gains on dispositions for the first quarter of 2017 consisted of $0.4 million related to the sale of certain gross overriding royalties and non-core undeveloped land for proceeds of $0.4 million.

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.

During the three months ended March 31, 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 (Q1 2017 – $3.2 million).

As at March 31, 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*)**
April 2018 – August 2018	33,611	–	2.81	–
April 2018 – August 2018(1)	33,611	2.58	–	(7,610)

(1) The Company has fixed the cost of net retained shallow gas obligations at $7.6 million to be paid over the remaining April to August 2018 period.

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

	March 31, 2018	December 31, 2017
Balance, beginning of period	**$ 46,704**	$ 47,159
Additions	**120**	1,948
Acquisitions	**–**	199
Non-cash exploration and evaluation expense	**–**	(2,602)
Balance, end of period	**$ 46,824**	$ 46,704

During the three months ended March 31, 2018, $0.2 million (Q1 2017 – $0.2 million) in costs were charged directly to E&E expense in net income (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 March 31, 2018, Perpetual had a $15.9 million TOU share margin loan ($16.0 million principal amount) secured by 1.67 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 March 31, 2018, the TOU share price declined in value, prompting the Company to voluntarily pay down the TOU share margin loan by $2.5 million to maintain the Lending Ratio at less than 55%, funded from borrowings on its Credit Facility. As at March 31, 2018, the Lending Ratio was 44% of the closing market value of the pledged TOU shares. The TOU share margin loan is a financial liability measured at amortized cost.

The effective interest rate on the TOU share margin loan as at March 31, 2018 was 4.0%. For the period ended March 31, 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 March 31, 2018.

8. REVOLVING BANK DEBT

As at March 31, 2018, the Company's reserve-based revolving credit facility (the "Credit Facility") had a borrowing limit (the "Borrowing Limit") of $65 million (December 31, 2017 – $65.0 million) under which $46.9 million was drawn (December 31, 2017 – $31.6 million) and $3.9 million of letters of credit had been drawn (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.

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 March 31, 2018 was 4.6%. For the period ended March 31, 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 $0.5 million (Q1 2017 – nil).

At March 31, 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).

	March 31, 2018	December 31, 2017
Balance, beginning of period	**$ 43,233**	$ –
Principal amount of Term Loan issued	**–**	45,000
Value allocated to warrants issued	**–**	(769)
Issue costs	**–**	(1,361)
Amortization of issue costs	**120**	363
Balance, end of period	**$ 43,353**	$ 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 March 31, 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

			March 31, 2018		December 31, 2017	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 Senior Notes	July 23, 2019	8.75%	**14,572**	**14,491**	14,572	14,476
2022 Senior Notes	January 23, 2022	8.75%(1)	**17,918**	**17,228**	17,918	17,204
			$ 32,490	**$ 31,719**	$ 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 9.75% until January 23, 2018 and 8.75% thereafter 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 March 31, 2018 the Senior Notes are presented net of $0.8 million in issue costs which are amortized using a weighted average effective interest rate of 9.6%.

At March 31, 2018, in addition to the restricted payment covenants noted above, the Senior Notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

11. PROVISIONS

	March 31, 2018	December 31, 2017
Decommissioning obligations	**$ 37,013**	$ 37,081
Restructuring costs	**1,419**	1,604
Total provisions	**$ 38,432**	$ 38,685
Provisions – current	**$ 1,792**	$ 2,580
Provisions – non-current	**36,640**	36,105
	$ 38,432	$ 38,685

a) Decommissioning obligations

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

	March 31, 2018	December 31, 2017
Decommissioning obligations, beginning of period	**$ 37,081**	$ 33,620
Obligations incurred	**278**	1,554
Obligations settled	**(553)**	(2,336)
Accretion (note 15)	**207**	775
Change in risk free interest rate	**–**	2,339
Change in estimates	**–**	1,129
Decommissioning obligations, end of period	**$ 37,013**	$ 37,081
Decommissioning obligations – current	**$ 1,590**	$ 2,243
Decommissioning obligations – non-current	**35,423**	34,838
	$ 37,013	$ 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:

	March 31, 2018	December 31, 2017
Undiscounted obligations	**$ 38,260**	$ 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)	(51)	(185)
Balance, March 31, 2018	**–**	**–**	**1,419**	**1,419**
Restructuring costs – current	–	–	202	202
Restructuring costs – non-current	–	–	1,217	1,217
Total	**$ –**	**$ –**	**$ 1,419**	**$ 1,419**

On February 1, 2017, Perpetual entered into 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

	March 31, 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	**472**	**905**	887	1,728
Shares held in trust purchases (b)	–	–	(708)	(1,000)
Shares held in trust issued (b)	**112**	**218**	520	1,437
Balance, end of period	**59,847**	**$ 1,337,961**	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 March 31, 2018, 336 thousand shares were held in trust (December 31, 2017 – 448 thousand).

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:

	March 31, 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, March 31, 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 March 31, 2018	2017
(thousands, except per share amounts)		
Net loss – basic	**$ (6,465)**	$ (14,172)
Effect of dilutive securities	**–**	–
Net loss – diluted	**$ (6,465)**	$ (14,172)
Weighted average shares		
Issued common shares	**59,759**	54,728
Effect of shares held in trust	**(414)**	(260)
Weighted average common shares outstanding – basic	**59,345**	54,468
Effect of dilutive securities	**–**	–
Weighted average common shares outstanding – diluted	**59,345**	54,468
Income (loss) per share – basic	**$ (0.11)**	$ (0.26)
Income (loss) per share – diluted	**$ (0.11)**	$ (0.26)

In computing per share amounts for the period ended March 31, 2018 and 2017, potentially issuable common shares through the share-based compensation plans and warrants were excluded as the Corporation had a net loss.

13. SHARE-BASED PAYMENTS

The components of share-based payments expense are as follows:

	Three months ended March 31, 2018	2017
Share options	**$ 239**	$ 319
Restricted rights	**–**	73
Performance share rights	**252**	290
Compensation awards	**315**	850
Share-based payments	**$ 806**	$ 1,532

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:

	March 31, 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	**1.60**	**(71)**	–	–
Expired	**–**	**–**	3.23	(96)
Balance, end of period	**1.68**	**3,916**	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	4.6	1.15	–	–
$1.30 to $1.57	1,775	3.2	1.42	451	1.42
$1.58 to $1.86	1,935	4.1	1.72	–	–
$1.87 to $5.97	166	1.4	4.01	126	4.67
Total	3,916	3.6	1.68	577	2.13

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 first quarter of 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. The estimated weighted average fair value of restricted rights granted during the three months ended March 31, 2018 was $0.66 per award (2017 – $1.58).

Restricted rights granted upon the exercise of performance share units (note 13c) and deferred shares (note 13d) vest on the grant date and have a 30-day exercise period. No value is assigned to restricted rights issued pursuant to those plans as the value and expense have been recognized pursuant to the grant date and expensed 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*)	**March 31, 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)	**15**	369
Exercised for common shares	**(472)**	(895)
Cancelled/forfeited	**(8)**	–
Balance, end of period	**543**	–

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 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 March 31, 2018, performance multipliers of 1.0 have been assumed for those unvested awards granted in 2017 and 2018 respectively. Fluctuations in share-based payments 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 three-month period ended March 31, 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*)	**March 31, 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 granted 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:

	March 31, 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	**1.63**	**(205)**	1.74	(120)
Expired	**–**	**–**	2.55	(64)
Balance, end of period	**1.68**	**2,063**	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	760	3.1	1.42	204	1.42
$1.58 to $1.86	1,224	4.1	1.72	–	–
$1.87 to $5.97	79	1.4	3.69	58	4.26
Total	2,063	3.7	1.68	262	2.05

The Company used the Black Scholes pricing model to calculate the estimated fair value of deferred options at the date of grant. During the first quarter of 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 first quarter of 2018, the Company did not grant any additional deferred shares.

The following table shows changes to these awards:

(*thousands*)	**March 31, 2018**	December 31, 2017
Balance, beginning of period	**1,857**	2,197
Granted	**–**	684
Exercised in exchange for shares held in trust (note 12)	**(112)**	(520)
Exercised in exchange for restricted rights	**(15)**	(369)
Cancelled/forfeited	**(71)**	(135)
Balance, end of period	**1,659**	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 first quarter of 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 March 31,	
	2018	2017
Oil and natural gas revenue		
Natural gas(1)	**15,451**	12,563
Oil(1)	**3,490**	3,451
NGL	**4,399**	2,144
Total oil and natural gas revenue	**23,340**	18,158

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

Included in accounts receivable at March 31, 2018 is $6.2 million of accrued oil and natural gas sales related to March 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 March 31,	
	2018	2017
Cash interest expense and income		
Interest on revolving bank debt	**468**	180
Interest on TOU share margin loan	**148**	214
Interest on Term Loan	**911**	145
Interest on Senior Notes	**721**	1,358
Dividend income from TOU share investment	**(133)**	–
Total cash interest expense and income	**2,115**	1,897
Non-cash finance expense		
Amortization of debt issue costs	**250**	94
Accretion on decommissioning obligations (note 11)	**207**	191
Change in fair value of gas over bitumen royalty financing	**(130)**	(1,239)
Change in fair value of TOU share put option margin loans	**–**	921
Total non-cash finance expense	**327**	(33)
Finance expenses recognized in net income (loss)	**2,442**	1,864

16. FINANCIAL RISK MANAGEMENT

Realized gains on commodity price derivatives recognized in net income for the three months ended March 31, 2018 were $0.7 million (Q1 2017 – $0.7 million). The realized gains on commodity price derivatives for the three months ended March 31, 2018 did not include the early settlement of any contracts prior to their maturity.

Natural gas contracts

At March 31, 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*)**
May 2018	Sold	20,300	0.93	(23)
September 2018 – March 2019	Sold	5,000	1.40	(372)

At March 31, 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*)
April 2018 – October 2018	Sold	7,500	(1.80)	76
May 2018 – October 2018	Bought	(7,500)	(1.92)	5
January 2019 – December 2019	Sold	12,500	(1.54)	(135)
January 2020 – December 2020	Sold	5,000	(1.43)	(18)

At March 31, 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*)
January 2019 – December 2019	Sold	7,500	(1.50)	63
January 2020 – December 2020	Sold	10,000	(1.40)	110

At March 31, 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*)
April 2018	Sold	5,000	1.18	(67)
April 2018 – October 2018	Sold	10,000	2.06	1,961
April 2018 – March 2019	Sold	10,000	1.41	(141)

Natural gas contracts - sensitivity analysis

As at March 31, 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 income for the period would change by $4.2 million. Fair value sensitivity was based on published forward AECO and NYMEX prices.

Oil contracts

At March 31, 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$/bbl*)	Ceiling price (*US$/bbl*)	Fair Value (*$ thousands*)
April 2018 – December 2018	250	50.00	58.40	(540)
April 2018 – December 2018	250	50.00	60.00	(435)

At March 31, 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*)
April 2018 – June 2018	500	(14.45)	276

At March 31, 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*)
April 2018 – December 2018	250	63.74	43

Oil contracts - sensitivity analysis

As at March 31, 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 income for the period would change by $1.0 million. Fair value sensitivity was based on published forward WTI and WCS prices.

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

	March 31, 2018	December 31, 2017
Physical natural gas contracts	**$ (739)**	$ 1,209
Financial natural gas contracts	**1,940**	1,506
Financial oil contracts	**(656)**	156
Fixed portion of retained shallow gas marketing arrangements [(1)]	**(7,610)**	(929)
Non-fixed portion of retained shallow gas marketing arrangements	**–**	(6,736)
Fair value of derivatives	**$ (7,065)**	$ (4,794)
Derivative assets – current	**1,875**	1,585
Derivative assets – non-current	**207**	1,506
Derivative liabilities – current	**(9,028)**	(7,885)
Derivative liabilities – non-current	**(119)**	–
Fair value of derivatives	**$ (7,065)**	$ (4,794)

(1) The Company has fixed the cost of net retained shallow gas obligations at $7.6 million to be paid over the remaining April to August 2018 period.

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

	Three months ended March 31,	
	2018	2017
Unrealized gain (loss) on financial oil contracts	**(812)**	1,238
Unrealized gain (loss) on financial natural gas contracts	**434**	(3,621)
Unrealized gain (loss) on physical natural gas contracts	**(1,948)**	607
Unrealized gain on forward foreign exchange contracts	**–**	5,022
Unrealized change in fair value of commodity price derivatives	**(2,326)**	3,246
Realized gain (loss) on financial oil contracts	**424**	(973)
Realized gain on financial natural gas contracts	**267**	5,898
Realized loss on forward foreign exchange contracts	**–**	(4,178)
Change in fair value of commodity price derivatives	**(1,635)**	3,993

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 bears 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:

As at March 31, 2018	Gross	Netting(1)	Carrying Amount	Fair value Level 1	Level 2	Level 3
Financial assets						
Fair value through profit and loss						
TOU share investment	**36,434**	**–**	**36,434**	**36,434**	**–**	**–**
Derivatives	**2,692**	**(610)**	**2,082**	**–**	**2,082**	**–**
Financial liabilities						
Financial liabilities at amortized cost						
TOU share margin loan	**15,929**	**–**	**15,929**	**15,990**	**–**	**–**
Revolving bank debt	**46,912**	**–**	**46,912**	**47,123**	**–**	**–**
Senior Notes	**31,719**	**–**	**31,719**	**–**	**32,490**	**–**
Term Loan	**43,353**	**–**	**43,353**	**–**	**–**	**45,000**
Fair value through profit and loss						
Derivatives	**9,757**	**(610)**	**9,147**	**–**	**9,147**	**–**
Gas over bitumen royalty financing	**2,170**	**–**	**2,170**	**–**	**–**	**2,170**

(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; statements pertaining to type curves being exceeded, forecast average production; completions and development activities; infrastructure expansion and construction; estimated FDC required to convert proved plus probable non-producing and undeveloped reserves to proved producing reserves; 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", "available liquidity", "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 involves a high degree of discretion. 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 disposition of the Shallow Gas Properties, which management considers to not be related to cash flow from operating activities. Restructuring costs include employee downsizing costs and surplus office lease obligations. Commencing in the first quarter of 2018, the Company no longer excludes 'exploration and evaluation – geological and geophysical costs' (Q1 2018 and 2017 – nil) 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.

Available Liquidity: Available Liquidity is defined as Perpetual's Credit Facility Borrowing Limit, plus 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 net 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 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, excluding foreign exchange contracts is used by management to calculate the Corporation's net realized commodity prices, taking into account monthly settlements on financial crude oil and natural gas forward sales, collars and basis differentials. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices, and as such, any related realized gains or losses are considered part of the Corporation's realized price.

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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Executive Chairman

Susan L. Riddell Rose
President, Chief Executive Officer and Director

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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

OFFICERS

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Bank of Nova Scotia

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company