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 Perpetual team was deeply saddened by the passing of Clayton (Clay) H. Riddell, the Company's Founder and Executive Chairman, on September 15, 2018. He was a trailblazer in the Canadian oil and gas industry and was intensely committed to the responsible development of Canada's natural resources. Clay epitomized the Company's entrepreneurial spirit and his guidance and leadership is greatly missed.

The execution of our growth-oriented capital program at East Edson in 2017 set the stage for improved performance on all measures in the first nine months of 2018. Perpetual posted solid growth in adjusted funds flow for the nine-month period to $22.1 million, up 19% from the comparable 2017 period. Production growth of 19% relative to the nine months ended September 30, 2017, combined with stronger oil and natural gas liquids ("NGL") prices, a 4% reduction in per unit operating costs and a 25% reduction in royalties, resulted in a modest decline in per unit operating netbacks, largely offsetting the precipitous drop in Western Canadian natural gas prices.

Natural gas prices in Alberta continued to experience weakness during the third quarter of 2018, with average AECO Daily Index prices a further 18% lower than the depressed third quarter prices experienced a year ago. In mid-2017, AECO prices became disconnected from the North American market as production growth in the Western Canadian Sedimentary Basin outpaced access to markets outside of Western Canada and local market demand, aggravated by the management of pipeline maintenance activities. Perpetual's proactive market diversification strategy implemented in 2017 provided a 98% uplift over average AECO Daily Index prices during the third quarter (Q3 2017 – nil) and importantly, will continue to provide for enhanced risk management through the expected future periods of volatile natural gas prices in Western Canada related to market access constraints.

Heavy oil prices, as measured by the price of Western Canadian Select, were 29% higher than the third quarter of 2017, as global oil inventories are returning to their 5-year average levels. The increase of WTI was related to the reduction in global oil inventories in 2018, stemming from the OPEC production cuts that began January 1, 2017, continued steep declines in Venezuelan production, and the pending reinstatement of sanctions on Iranian production by the United States beginning in November 2018. However, differentials have widened substantially in the fourth quarter of 2018 as refinery outages combined with oversupply relative to pipeline and rail export capacity in Western Canada, have materially reduced oil prices for Canadian producers.

Adjusting to the volatile commodity price environment, Perpetual strategically directed investment almost exclusively to its heavy oil business in the third quarter of 2018, while modest spending returns to East Edson during the fourth quarter to opportunistically align natural gas production additions with the higher natural gas prices anticipated in the winter heating period. Capital spending is forecast to be very limited in the early part of next year as the Company prudently targets investment to grow oil production in the second half of 2019 when differentials are expected to recover as anticipated by the forward market.

THIRD QUARTER 2018 HIGHLIGHTS

- During the third quarter, operations were focused on growing the Company's heavy oil production in the Mannville area of Eastern Alberta. Capital expenditures included the drilling of three (3.0 net) new heavy oil horizontal wells, along with a fourth well that was re-entered to add three additional laterals. Two of the wells were tied-in to production at the end of the third quarter, and the remaining two came online during the first week of October. The new drills are performing as forecast. The Company also re-purposed an inventoried generator and installed it at Mannville to improve the value of shallow gas sales by selling power to the grid. In addition, Perpetual acquired the remaining 33% working interest in a Mannville heavy oil pool, adding approximately 65 boe/d of production, for $1.3 million.

- Perpetual's proactive market diversification strategy implemented in 2017 provided a 98% uplift over average AECO Daily Index prices during the third quarter of 2018 (Q3 2017 – nil). The 40,000 MMBtu/d market diversification contract is priced based on daily index prices at five pricing hubs outside of Alberta that generally track North American NYMEX prices and is effectively mitigating the impact of low and volatile natural gas prices at the Alberta AECO hub.

- On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy of Sequoia Resources Corp. ("Sequoia"), with the Alberta Court of Queen's Bench (the "Court"), against Perpetual. The claim relates to an almost two-year-old transaction when, on October 1, 2016, Perpetual closed the disposition of shallow gas assets (the "Shallow Gas Disposition") to an arm's length third party at fair market value at the time after an extensive and lengthy marketing, due diligence and negotiation process. This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or award damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and an application to the Court to dismiss all claims has been made on the basis that there is no merit to any of them and that they constitute an abuse of process. Perpetual's Application for Summary Dismissal is scheduled to be heard on November 8, 2018 with the Court's decision expected by the end of December. Management expects that the Company is more likely than not to be successful in defending against the claim such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in these financial statements.

- Cash flow from operating activities in the third quarter of 2018 was $6.7 million ($0.11/share) up 16% compared to cash flow from operating activities in the prior year period of $5.8 million ($0.10/share).

- Adjusted funds flow in the third quarter of 2018 was $5.2 million ($0.09/share), down 37% from the prior year period of $8.2 million ($0.14/share) due to decreased production and higher cash costs largely related to the remediation of the produced water pipeline break at Mannville and the Sequoia litigation, despite higher realized revenue per boe. Adjusted funds flow was $5.86/boe in the third quarter of 2018, down 32% from the prior year period of $8.63/boe and 28% lower than the second quarter of 2018 ($8.12/boe).

Production and Operations

- Perpetual's exploration and development spending in the third quarter of 2018 was $4.3 million, 83% lower than $25.4 million spent in the comparative period of 2017. The three (3.0 net) third quarter 2018 drills at Mannville were development wells targeting higher pressure areas of existing pools under waterflood, and production results to date are consistent with expectations. The fourth well was a re-entry to add three additional legs to an existing horizontal well to evaluate the application of multi-lateral drilling technology for the large resource in place in tighter Mannville oil pools. Initial results are positive, and the Company will continue to monitor performance.

- Third quarter capital spending also included the installation of a one-megawatt electricity generator at the Mannville plant site. The project will utilize fuel gas produced from the Mannville gas plant and convert it to electricity which will be sold on the grid, effectively increasing the value of Mannville gas production. The generator was sourced from internal inventory, minimizing the net cost of the project. The power project came online in the first week of October.

- Spending at the East Edson property in West Central Alberta represented just 4% of total exploration and development expenditures in the third quarter of 2018, and consisted primarily of maintenance activities associated with reconfiguring equipment for higher NGL recoveries. East Edson capital activity for the nine months ended September 30, 2018 included the drilling of one (1.0 net) Wilrich extended reach horizontal ("ERH") natural gas well and the frac and tie-in of two wells drilled in the fourth quarter of 2017. The 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.

- Third quarter production averaged 9,569 boe/d, down 7% from 10,330 boe/d in the comparative period of 2017. The decrease was driven by approximately 700 boe/d of production that was shut-in at East Edson throughout the second and third quarters at the request of the Alberta Energy Regulator after the operator of record, Sequoia, filed for bankruptcy. The four well pad at East Edson is 100% owned by Perpetual, but Sequoia was designated operator to facilitate the recovery of Perpetual's gas over bitumen royalty credit amounts held by Sequoia following the Shallow Gas Disposition. Production was shut-in, pending the completion of the bankruptcy trustee's review of Sequoia's assets and operations. Perpetual anticipates that production from these wells will resume by early 2019. Compared to the second quarter of 2018, production was down 10%. The decrease was driven by natural declines in East Edson resulting from limited capital investment during 2018 in response to low AECO natural gas prices.

- Perpetual's petroleum and natural gas ("P&NG") revenue, before derivatives, for the three months ended September 30, 2018 of $20.5 million increased 2% from the third quarter of 2017 despite a 7% decrease in average daily production. Third quarter P&NG revenue was comparable to the second quarter of 2018, despite the 10% decline in average daily production.

- Natural gas revenue, before derivatives, of $11.3 million in the third quarter of 2018 comprised 55% (Q3 2017 – 66%) of total P&NG revenue while natural gas production was 81% (Q3 2017 – 84%) of total production. Perpetual's 40,000 MMBtu/d market diversification contract contributed $5.0 million to revenue ($1.17/Mcf) over the AECO Daily Index price in the quarter. Natural gas revenue decreased 14% from $13.2 million in the third quarter of 2017, reflecting the impact of the 9% decrease in natural gas production volumes driven by natural declines following limited capital investment in East Edson during the second and third quarters of 2018.

- Oil revenue of $5.4 million represented 26% (Q3 2017 – 21%) of total P&NG revenue while oil production was 11% (Q3 2017 – 9%) of total production. Oil revenue was 29% higher than the same period in 2017 due to the 13% increase in realized oil prices combined with the 4% increase in crude oil production. The improved WCS average prices are a function of a higher WTI US$ benchmark price and stronger US dollar, which more than offset the wider WCS differential compared to the prior year period. Oil revenue was 7% higher than the second quarter of 2018, due to the 5% increase in crude oil production.

- NGL revenue for the third quarter of 2018 of $3.8 million represented 19% (Q3 2017 – 13%) of total P&NG revenue while NGL production was just 8% (Q3 2017 – 7%) of total Company production. NGL revenue increased by 43% over the prior year period while NGL production remained flat despite declining natural gas production, reflecting higher condensate yields and a 43% increase in NGL prices compared to the prior year period. NGL revenue was 16% lower than the second quarter of 2018, due to the 9% decline in NGL production combined with an 8% decrease in realized NGL pricing.

- Royalty expenses for the third quarter of 2018 were $2.7 million, consistent with the comparable period of 2017 and the second quarter of 2018. The combined average royalty rate on P&NG revenue remained consistent with the prior year period at approximately 13%. For the nine months ended September 30, 2018, sharply lower Alberta Gas Reference prices (43% decline) and AECO Daily Index prices (35% decline) used to calculate crown and freehold natural gas royalties respectively, contributed to most of the decrease in royalty expense from $9.3 million to $8.3 million, despite the 20% increase in natural gas production over the same period.

- Total production and operating expenses were up 72% on a unit-of-production basis to $6.02/boe for the third quarter of 2018, compared to $3.50/boe for the comparable period of 2017. The increase was driven by remediation costs of $0.8 million ($0.91/boe) incurred from the Mannville produced water spill and the absence of a $0.9 million ($0.95/boe) non-recurring adjustment in the prior year period associated with third party processing facilities that were sold as part of the Shallow Gas Disposition. Remediation work related to the pipeline break at Mannville was completed in early October. Production and operating expenses increased 23% from $4.3 million in Q2 2018, with the cost per boe increasing 35% due to the impact of increased costs on declining production volumes.

- Transportation costs in the third quarter of 2018 were $1.6 million, up 19% from the prior year period due to the increase in firm natural gas transportation commitments at East Edson to 78 MMcf/d that commenced in December 2017. Transportation costs averaged $1.71/boe at West Central compared to $2.22/boe for production from Eastern Alberta. On a unit-of-production basis, transportation costs were $1.81/boe in the third quarter, up 29% from the prior year period due to the impact of fixed firm capacity transportation costs against lower production.

- Perpetual's operating netback of $11.0 million ($12.49/boe) in the third quarter of 2018 decreased 18% from $13.4 million ($14.12/boe) in the comparative period of 2017. This decrease was due to the 7% decrease in production caused by natural declines at East Edson, combined with a 12% decrease in operating netback per boe. The lower operating netback per boe in the third quarter of 2018 reflected a 7% increase in realized revenue per boe due to improved crude oil and NGL pricing. Higher realized selling prices were more than offset by the associated increase in royalties as well as higher operating costs. Compared to the second quarter of 2018, Perpetual's operating netback decreased 10% from $13.85/boe due primarily to the increased production and operating expenses resulting from the Mannville produced water spill.

Financial Highlights

- During the third quarter of 2018, cash general and administrative ("G&A") expense was $3.8 million, a slight decrease from the prior year period of $3.9 million. Cash G&A expense increased by $0.3 million over the second quarter of 2018, due primarily to Sequoia litigation defence costs. The Company expects the majority of future defence costs will be covered by insurance. Compared to the prior year period, third quarter 2018 overhead recoveries decreased by 60% due to reduced capital spending, combined with a reduction in expenditures on decommissioning obligations. On a unit-of-production basis, total G&A expense of $3.86/boe for the three months ended September 30, 2018 was up 29% from the prior year period due to the impact of decreasing production.

- Total cash interest expense and income of $2.2 million for the three months ended September 30, 2018 was 10% higher than the prior year period (Q3 2017 – $2.0 million) due to increased debt levels, partially offset by dividend income of $0.2 million ($0.10 per TOU share) received from the TOU share investment during the third quarter of 2018 (Q3 2017 – nil). Total cash interest expense for the third quarter of 2018 was consistent with the previous quarter but increased on a unit-of-production basis from $2.22/boe to $2.51/boe due to the impact of decreasing production.

- Net loss for the third quarter of 2018 was $12.3 million ($0.20/share), compared to a net loss of $8.1 million ($0.14/share) in the comparative period of 2017. The increase in net loss from the prior year period was due primarily to a $7.2 million ($0.12/share) write-down of exploration and evaluation ("E&E") assets during the third quarter of 2018.

- At September 30, 2018, Perpetual had total net debt of $105.4 million, down $0.6 million from December 31, 2017, as net cash flow from operations and net proceeds from non-core asset sales exceeded capital expenditures and acquisitions during the year-to-date period. The net working capital deficiency of $7.5 million at September 30, 2018 decreased by $8.9 million from December 31, 2017, due to reduced capital expenditures during the third quarter of 2018 compared to the fourth quarter of 2017, resulting in lower payables at September 30, 2018 compared to December 31, 2017. The decrease in the net working capital deficiency was funded by a corresponding increase in revolving bank debt. Compared to June 30, 2018, net debt increased 5% from $100.2 million, reflecting the final settlement of the gas marketing contract related to the Shallow Gas Disposition.

- As at September 30, 2018, 60% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow improved to 3.0 times at September 30, 2018 (December 31, 2017 – 3.4 times).

2018 STRATEGIC PRIORITIES

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

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

Grow value of Greater Edson liquids-rich gas

- Production in West Central Alberta, primarily at East Edson, declined 7% relative to the third quarter of 2017 to 7,695 boe/d, comprising 80% of total Company production. The decrease was largely driven by the approximately 700 boe/d of shut-in production from the four well pad at East Edson. The four well pad is 100% owned by Perpetual, but Sequoia was designated operator to facilitate the recovery of Perpetual's gas over bitumen royalty credit amounts held through Sequoia following the Shallow Gas Disposition. The bankruptcy trustee has reviewed our property claim and agreed to cooperate to effect the license transfers required to recommence production. Perpetual anticipates that production from these wells will resume in early 2019.

- The Company has intentionally deferred capital spending at East Edson to preserve value during this period of very low and volatile prices in Western Canada due to restrictions on TCPL's system related to maintenance and debottlenecking activities and lack of new pipeline egress out of the province.

- Despite the 8% decrease in West Central natural gas production, NGL production was flat compared to the 2017 quarter as liquids yields increased to 17 bbl/MMcf due to the reconfiguration of plant processing equipment and higher NGL production from wells tied-in and reactivated during the first quarter of 2018.

- Spending at the East Edson property was just $0.2 million in the third quarter of 2018, consisting primarily of maintenance activities. East Edson capital activity for the nine months ended September 30, 2018 included the drilling of one (1.0 net) Wilrich ERH well and the frac and tie-in of two wells drilled in the fourth quarter of 2017. Frac operations on the ERH well drilled during the first quarter commenced in early November with production expected to follow imminently to align high initial production rates with higher anticipated winter natural gas prices.

- Despite lower production on a substantially fixed operating cost base, unit operating costs were down to $2.44/boe in the third quarter of 2018 (Q3 2017 - $2.54/boe).

- Operating netbacks in West Central Alberta were $12.84/boe, down just 4% relative to Q3 2017 despite lower AECO natural gas prices.

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

- Perpetual continued to advance its methane emissions reduction strategy through inventory and assessment of all pressure and level controllers at East Edson. The Company also received approval for an alternative metering scheme for new wells which will reduce fugitive emissions while reducing tie-in capital.

Grow value of Eastern Alberta portfolio

- Crude oil production in Eastern Alberta grew by 6% relative to the third quarter of 2017 and 7% from the second quarter of 2018, reflecting strong waterflood response and steady performance from the wells drilled during the first quarter of 2018.

- Three (3.0 net) development wells targeting higher pressure areas of existing pools under waterflood were drilled, completed and tied-in, and production results to date are consistent with expectations.

- An existing horizontal well drilled in 2017 and producing from the Sparky formation was re-entered to add three additional legs in order to evaluate the application of multi-lateral drilling technology for the large resource in place in tighter Mannville oil pools. Initial results are positive, and the Company will continue to monitor performance as over ten follow up multi-lateral locations have been identified in this pool if stabilized performance supports further investment.

- During the third quarter of 2018, Perpetual spent $1.3 million to acquire the remaining 33% working interest in a Company-operated Mannville heavy oil pool, adding approximately 65 boe/d of production. Two of the development wells drilled during the third quarter targeted this pool, therefore the acquisition increased the Company's net working interest in the drilling projects to 100%, and immediately increased production from the acquired assets.

- Capital was invested in the installation of a one-megawatt electricity generator at the Mannville plant site. The project utilizes fuel gas produced from the Mannville gas plant and converts it to electricity which is sold on the grid, effectively increasing the value of Mannville gas production. The generator was sourced from internal inventory, minimizing the net cost of the project. The power project came online in the first week of October. The economics of an expansion to a five-megawatt generating capacity is being evaluated.

- Natural gas production in Eastern Alberta was 5.2 MMcf/d, down 19% from the comparative period of 2017, due to deferred spending on shallow gas recompletion activity given low natural gas prices.

- Close to $0.1 million was spent on abandonment and reclamation projects in Eastern Alberta during the quarter, including well abandonments, pipeline discontinuations and abandonments, and third party environmental spending as well as reclamation work. As part of Perpetual's focus on well and pipeline abandonment and reclamation, five reclamation certificates were received from the Alberta Energy Regulator during the third quarter of 2018 which will result in the cessation of associated property tax and surface lease expenses.

- Production and operating expenses increased in the third quarter of 2018 due to remediation costs incurred from the Mannville produced water spill and the absence of a $0.9 million ($0.95/boe) non-recurring third-party processing fee adjustment received in the prior year period. Production and operating expenses in Eastern Alberta were $20.75/boe during the third quarter of 2018 (Q2 2018 – $14.82/boe; Q3 2017 - $7.45/boe).

- The Mannville heavy oil drilling program for the second half of 2018 has been reduced from the Q3 Guidance of 4.3 – 8.3 net wells to the 3.0 net wells, plus one re-entry executed in the third quarter. The expanded drilling program was deferred due to the alternative use of funds to acquire the partner interest in the Mannville heavy oil pool and also to allow more time to monitor performance from the first quad lateral re-entry while heavy oil differentials recover during the first half of 2019 as indicated by the forward market.

- Planning activities are well underway for a sizable heavy oil drilling program following 2019 break-up. The Company expects to drill at least 10 horizontal wells, the majority of which are expected to employ multi-lateral drilling technology.

Advance high impact opportunities

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

Optimize balance sheet for growth

- Perpetual's 40,000 MMBtu/d market diversification contract contributed $5.0 million of incremental revenue ($1.17/Mcf) over the AECO Daily Index price in the quarter ($12.7 million and $0.84/Mcf for the nine months ended September 30, 2018). The five-year market diversification contract is priced based on daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) outside of Alberta that generally track North American NYMEX prices. These contracts effectively shift the sales point to the basket of five North American natural gas hub pricing points, diversifying the Company's natural gas price exposure from AECO. Based on current futures prices, Perpetual expects these gas price diversification contracts will provide a significant premium over AECO prices for the remainder of 2018 and 2019.

- Adjusted funds flow in the third quarter of 2018 was $5.2 million ($0.09/share), down 37% from the prior year period of $8.2 million ($0.14/share) due to decreased production and higher cash costs, and despite higher realized revenue per boe. Adjusted funds flow was $5.86/boe in the third quarter of 2018, down 32% from the prior year period of $8.63/boe.

- During the first quarter of 2018, Perpetual fixed the cost of the floor price protection embedded in retained marketing arrangements related to the Shallow Gas Disposition for the open period from April 1, 2018 to August 31, 2018 at a cost of $7.6 million. Remaining payments of $3.1 million were made during the third quarter (nine months ended September 30, 2018 – $8.5 million) related to this fixed floor price protection. The retained marketing arrangements have since expired.

- At September 30, 2018, Perpetual had total net debt of $105.4 million, down $0.6 million from December 31, 2017, as net cash flow from operations and financing activities and net proceeds from non-core asset sales exceeded capital expenditures and acquisitions during the year-to-date period. Total net debt of $105.4 million at September 30, 2018 was up $5.2 million (5%) from June 30, 2018 as the net working capital deficiency increased from $3.1 million at June 30, 2018 to $7.5 million at September 30, 2018, caused by increased payables resulting from the third quarter 2018 capital program, final payments for the retained marketing arrangements, and a $1.2 million decrease in the market value of the TOU share investment.

- As at September 30, 2018, 60% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow improved to 3.0 times at September 30, 2018 (December 31, 2017 – 3.4 times).

- On November 7, 2018, the revolving bank debt borrowing limit was reduced from $60 million to $55 million by the Company's lenders with the next borrowing limit redetermination scheduled on or prior to May 31, 2019. If the repayment term of the revolving bank debt is not extended at that time, all outstanding advances will become payable on May 31, 2019. After giving effect to the $5 million reduction in the borrowing limit, Perpetual had available liquidity at September 30, 2018 of $30.9 million, comprised of an unutilized borrowing limit of $8.9 million and the market value of its Tourmaline share investment net of the associated margin demand loan, of $22.0 million.

OUTLOOK

Please refer to "Management's Discussion and Analysis – Outlook" on pages 9 to 11 of this third quarter 2018 report for updated 2018 and 2019 capital spending and production guidance.

Susan Riddell Rose
President and Chief Executive Officer
November 7, 2018

Financial and Operating Highlights						
	Three months ended September 30			**Nine months ended September 30**		
(Cdn$ thousands, except volume and per share amounts)	**2018**	2017	Change	**2018**	2017	Change
Financial						
Oil and natural gas revenue	**20,504**	20,026	2%	**64,618**	57,912	12%
Net loss	**(12,259)**	(8,082)	(52%)	**(20,049)**	(29,473)	32%
Per share – basic and diluted[2]	**(0.20)**	(0.14)	(43%)	**(0.33)**	(0.51)	35%
Cash flow from operating activities	**6,729**	5,778	16%	**26,362**	8,217	221%
Per share[2]	**0.11**	0.10	10%	**0.44**	0.14	214%
Adjusted funds flow[1]	**5,155**	8,199	(37%)	**22,103**	18,574	19%
Per share[2]	**0.09**	0.14	(36%)	**0.37**	0.32	16%
Revolving bank debt	**42,431**	29,262	45%	**42,431**	29,262	45%
Senior notes, at principal amount	**32,490**	32,490	–	**32,490**	32,490	–
Term loan, at principal amount	**45,000**	35,000	29%	**45,000**	35,000	29%
TOU share margin demand loan, at principal amount	**15,681**	18,740	(16%)	**15,681**	18,740	(16%)
TOU share investment	**(37,675)**	(42,304)	(11%)	**(37,675)**	(42,304)	(11%)
Net working capital deficiency[1]	**7,484**	19,556	(62%)	**7,484**	19,556	(62%)
Total net debt[1]	**105,411**	92,744	14%	**105,411**	92,744	14%
Net capital expenditures						
Capital expenditures	**4,343**	25,392	(83%)	**21,271**	53,988	(61%)
Net payments (proceeds) on acquisitions and dispositions	**4,341**	680	538%	**(1,745)**	1,452	(220%)
Net capital expenditures	**8,684**	26,072	(67%)	**19,526**	55,440	(65%)
Common shares outstanding *(thousands)*[3]						
End of period	**60,524**	59,316	2%	**60,524**	59,316	2%
Weighted average – basic and diluted	**60,468**	59,152	2%	**59,900**	57,572	4%
Operating						
Average production						
Natural gas *(MMcf/d)*	**46.9**	51.8	(9%)	**55.2**	45.9	20%
Oil *(bbl/d)*	**1,022**	978	4%	**965**	968	–
NGL *(bbl/d)*	**730**	733	–	**794**	627	27%
Total *(boe/d)*	**9,569**	10,330	(7%)	**10,965**	9,240	19%
Average prices						
Realized natural gas price *($/Mcf)*	**2.83**	2.99	(5%)	**2.69**	3.65	(26%)
Realized oil price *($/bbl)*	**48.57**	43.01	13%	**50.06**	39.86	26%
Realized NGL price *($/bbl)*	**56.02**	39.06	43%	**58.19**	43.59	33%
Wells drilled						
Natural gas – gross (net)	**–**	5 (4.4)		**1 (1.0)**	12 (11.4)	
Oil – gross (net)	**3 (3.0)**	–		**6 (6.0)**	4 (3.3)	
Total – gross (net)	**3 (3.0)**	5 (4.4)		**7 (7.0)**	16 (14.7)	

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

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc.'s ("Perpetual", the "Company" or the "Corporation") operating and financial results for the three and nine months ended September 30, 2018 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's unaudited condensed interim consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2018 as well as audited consolidated financial statements and accompanying notes for the years ended December 31, 2017 and 2016. The MD&A should be read in conjunction with the Corporation's MD&A for the year ended December 31, 2017 as disclosure which is unchanged from the December 31, 2017 MD&A has not been duplicated herein. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are referred to the advisories for additional information regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information and Statements" section of this MD&A. The date of this MD&A is November 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", "net bank debt", "operating netback", "realized revenue" and "enterprise value" used in this MD&A are not recognized under GAAP. Management believes that in addition to net income (loss) and net cash flows from (used in) operating activities as defined by GAAP, these terms are useful supplemental measures to evaluate performance. Users are cautioned however that these measures should not be construed as an alternative to net income (loss) or net cash flows from (used in) operating activities determined in accordance with GAAP as an indication of Perpetual's performance and may not be comparable with the calculation of similar measurements by other entities.

Adjusted funds flow: Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations and meet its financial obligations. Adjusted funds flow is calculated based on cash flows from (used in) operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations since Perpetual believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. The Company has also deducted the change in gas over bitumen royalty financing from adjusted funds flow, in order to present these payments net of gas over bitumen royalty credits received. These payments are indexed to gas over bitumen royalty credits and are recorded as a reduction to the Corporation's gas over bitumen royalty financing obligation in accordance with IFRS. Additionally, the Company has excluded payments of restructuring costs associated with the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition"), which management considers to not be related to cash flow from operating activities. Restructuring costs include employee downsizing costs and surplus office lease obligations. Commencing in the first quarter of 2018, the Company no longer excludes 'exploration and evaluation – geological and geophysical costs' (Q3 2018 – $0.1 million; and Q3 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 September 30,		Nine months ended September 30,	
(*$ thousands, except per share and per boe amounts*)	**2018**	2017	**2018**	2017
Net cash flows from operating activities	**6,729**	5,778	**26,362**	8,217
Changes in non-cash working capital	**(1,698)**	1,675	**(4,825)**	8,701
Expenditures on decommissioning obligations	**252**	887	**1,158**	1,424
Change in gas over bitumen royalty financing	**(179)**	(558)	**(878)**	(2,084)
Payments of restructuring costs	**51**	417	**286**	2,316
Adjusted funds flow	**5,155**	8,199	**22,103**	18,574
Adjusted funds flow per share	**0.09**	0.14	**0.37**	0.32
Adjusted funds flow per boe	**5.86**	8.63	**7.38**	7.36

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 demand loan. Management uses available liquidity to assess the ability of the Company to finance capital expenditures, expenditures on decommissioning obligations and meet financial obligations.

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

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands, except per boe amounts*)	**2018**	2017	**2018**	2017
Royalties	**2,658**	2,614	**8,311**	9,322
Production and operating	**5,302**	3,326	**14,378**	12,561
Transportation	**1,590**	1,331	**4,579**	3,572
General and administrative	**3,396**	2,850	**9,837**	9,093
Cash interest expense and income	**2,207**	1,998	**6,465**	5,816
Cash costs	**15,153**	12,119	**43,570**	40,364
Cash costs per boe	**17.21**	12.75	**14.56**	16.00

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 demand 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 demand loan, revolving bank debt, senior notes, and current portion of provisions.

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

Realized revenue: Realized revenue is the sum of realized natural gas revenue, realized oil revenue and realized NGL revenue which includes realized gains (losses) on financial natural gas, crude oil and foreign exchange contracts but excludes any realized gains (losses) resulting from contracts related to the disposition of the Shallow Gas Properties. Realized revenue, including foreign exchange contracts, is used by management to calculate the Corporation's net realized commodity prices, taking into account monthly settlements on financial crude oil and natural gas forward sales, collars, basis differentials, and forward foreign exchange sales. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices and foreign exchange rates, and as such, any related realized gains or losses are considered part of the Corporation's realized price.

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

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

THIRD QUARTER 2018 HIGHLIGHTS

Natural gas prices in Alberta continued to experience weakness during the third quarter of 2018, with average AECO Daily Index prices a further 18% lower than the depressed third quarter prices experienced a year ago. Perpetual's proactive market diversification strategy implemented in 2017 provided a 98% uplift over average AECO Daily Index prices during the third quarter (Q3 2017 – nil).

Exploration and development spending for the third quarter of 2018 was $4.3 million, of which 96% was incurred at Mannville to drill three (3.0 net) new heavy oil horizontal wells and one (1.0 net) re-entry where three horizontal laterals were added to an existing horizontal well. Two of the four wells were tied-in to production at the end of the third quarter, and two came online during the first week of October.

Production averaged 9,569 boe/d in the third quarter of 2018, down 7% from the comparable period in 2017. The decrease was driven by approximately 700 boe/d of production that was shut-in at East Edson throughout the second and third quarters at the request of the Alberta Energy Regulator after the operator of record, Sequoia Resources Corp. ("Sequoia"), filed for bankruptcy. The four well pad at East Edson is 100% owned by Perpetual, but Sequoia was designated operator to facilitate the recovery of Perpetual's gas over bitumen royalty credit amounts held by Sequoia following the Shallow Gas Disposition. Production was shut-in, pending the completion of the bankruptcy trustee's review of Sequoia's assets and operations. Perpetual anticipates that production from these wells will resume by early 2019. Compared to the second quarter of 2018, production was down 10%. The decrease was driven by natural declines in East Edson resulting from limited capital investment during 2018 in response to low AECO natural gas prices.

Realized revenue was $23.34/boe in the third quarter of 2018 compared to $21.77/boe in the prior year period, up 7% as the impact of the 18% reduction in the AECO Daily Index natural gas price from the comparative period was largely offset by higher sales prices realized through Perpetual's natural gas market diversification contract to markets outside of Alberta, combined with higher oil and natural gas liquids ("NGL") selling prices in the third quarter of 2018. Deliveries to the market diversification contract commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018. The market diversification contract is expected to continue to provide for enhanced risk management through future periods of volatile natural gas prices in Western Canada related to market access constraints.

Cash costs were $17.21/boe in the third quarter of 2018, up 35% compared to the prior year period due to higher operating costs resulting from a produced water spill at the Company's Mannville heavy oil operation. Clean-up costs of approximately $0.8 million were incurred during the quarter, increasing operating costs by $0.91/boe. Additionally, operating costs in the comparative period of 2017 were reduced by a $0.9 million ($0.95/boe) non-recurring adjustment associated with third party processing facilities that were sold as part of the Shallow Gas Disposition. Operating costs at West Central Alberta were $2.44/boe for the three months ended September 30, 2018, down 4% from the prior year period. Total general and administrative expenses increased by 19% over the prior year period, due primarily to Sequoia litigation defence costs, combined with reduced overhead recoveries following the reduction in capital expenditures.

The net loss for the third quarter of 2018 was $12.3 million ($0.20/share), compared to a net loss of $8.1 million ($0.14/share) in the comparative period of 2017. The increase in net loss from the prior year period was due primarily to a $7.2 million ($0.12/share) write-down of E&E assets during the third quarter of 2018.

Cash flow from operating activities in the third quarter of 2018 was $6.7 million ($0.11/share) compared to cash flow from operating activities in the prior year period of $5.8 million ($0.10/share).

Adjusted funds flow in the third quarter of 2018 was $5.2 million ($0.09/share), down 37% from the prior year period of $8.2 million ($0.14/share) due to decreased production and higher cash costs, and despite higher realized revenue per boe. Adjusted funds flow was $5.86/boe in the third quarter of 2018, down 32% from the prior year period of $8.63/boe.

On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy of Sequoia, with the Alberta Court of Queen's Bench (the "Court"), against Perpetual. The claim relates to an almost two-year-old transaction when, on October 1, 2016, Perpetual closed the Shallow Gas Disposition to an arm's length third party at fair market value at the time after an extensive and lengthy marketing, due diligence and negotiation process. This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or award damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and an application to the Court to dismiss all claims has been made on the basis that there is no merit to any of them and that they constitute an abuse of process. Perpetual's Application for Summary Dismissal is scheduled to be heard on November 8, 2018 with the Court's decision expected by the end of December.

OUTLOOK

2018 capital spending and production guidance

Perpetual anticipates 2018 exploration and development capital expenditures of approximately $25 to $26 million ($4 to $5 million for the fourth quarter), reducing the upper end of its previous guidance of $25 to $30 million provided in its second quarter financial and operating results press release dated August 2, 2018 (the "Q3 Guidance"). The Mannville heavy oil drilling program for the second half of 2018 has been reduced from the Q3 Guidance of 4.3 – 8.3 net wells to 3.0 net wells, plus one re-entry. The expanded drilling program was deferred to allow more time to monitor performance from the first quad lateral re-entry, to remediate the produced water spill at Mannville, and due to the alternative use of funds to acquire a partner's interest in one of the Company's operated Mannville heavy oil pools. Furthermore, the Company expects that heavy oil differentials will narrow in the second half of 2019, improving economics for the heavy oil drills.

At East Edson, one horizontal well drilled in the first quarter of 2018 will be completed and tied-in during the fourth quarter. Additionally, the installation of field compression and a sweetening tower is targeting to restore several higher liquids ratio wells back to production. The timing of the capital activity is designed to align high initial production rates with higher anticipated winter natural gas prices.

Decommissioning expenditures are anticipated to be $0.5 to $1.0 million for the remainder of 2018, consistent with Q3 Guidance. Capital spending during the remainder of 2018 will be funded from adjusted funds flow.

Production for 2018 is expected to be 10,250 boe/d to 10,750 boe/d, down slightly from Q3 Guidance, as the re-start of production from the 700 boe/d four well pad at Edson is not forecast to commence until early 2019, and extremely low AECO gas prices in October and early November have caused the Company's voluntary production shut-in strategy to be implemented on a number of occasions. For the October 2018 through March 2019 period, Perpetual has fixed the price on 15,000 GJ/d at $1.41/GJ AECO with the remainder of its production sold at daily index prices at the Chicago, Dawn, Empress, Malin and Michcon markets through its 40,000 MMBtu/d market diversification contract. If AECO prices temporarily weaken, Perpetual's fixed price AECO position provides the ability to shut-in production and purchase gas to deliver against pre-sold commitments while preserving reserves and future deliverability capability. Perpetual has costless collar and fixed price WTI oil sales arrangements in place to sell 750 bbl/d at an average ceiling price of US$60.71/bbl for the remainder of 2018. Additionally, Perpetual has fixed the US$/Cdn$ exchange rate on approximately 53% of its US$ denominated sales at a rate of $1.30 for the remainder of 2018.

Cash costs of $15.00 to $15.50/boe are now anticipated for 2018, up slightly from Q3 Guidance, due to the produced water spill remediation costs incurred in the third quarter.

Adjusted funds flow for 2018 is anticipated to be in the $27 to $29 million range ($5 to $7 million for the remainder of 2018), consistent with Q3 Guidance. On a per share basis, adjusted funds flow for 2018 is anticipated to be $0.44 to $0.48 per share.

Guidance assumptions are as follows:

	Q4 Guidance	Q3 Guidance
Exploration and development expenditures (*$ millions*)	**$25 - $26**	$25 - $30
2018 cash costs (*$/boe*)	**$15.00 - $15.50**	$14.00 - $15.00
2018 average daily production (*boe/d*)	**10,250 – 10,750**	10,500 - 11,000
2018 average production mix (*%*)	**17% oil and NGL**	16% oil and NGL

Commodity price assumptions reflect market price levels as follows:

	Q4 Guidance	Q3 Guidance
2018 average NYMEX natural gas price (*US$/MMBtu*)	**$2.97**	$2.85
2018 average West Texas Intermediate ("WTI") oil price (*US$/bbl*)	**$67.11**	$65.24
2018 average Western Canadian Select ("WCS") differential (*US$/bbl*)	**($25.68)**	($23.62)
2018 average exchange rate (US$1.00 = Cdn$)	**$1.29**	$1.30

Year end 2018 net debt (net of the estimated market value of the Company's TOU share investment of approximately $35 million), is forecast at $104 - $107 million, up from Q3 Guidance of $98 - $103 million, due to a decrease in the market value of the Company's TOU share investment since the second quarter. Current guidance is based on the following assumptions:

- Net debt at September 30, 2018 of $105.4 million
- Adjusted funds flow for the remainder of 2018 of $5 to $7 million
- Capital spending for the remainder of 2018 of $4 to $5 million
- Decommissioning expenditures for the remainder of 2018 of $0.5 to $1.0 million

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

2019 capital spending and production guidance

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

Forecast capital activity in Mannville for 2019 includes the drilling of 10 (10.0 net) new wells, targeting a mix of infill wells and step outs in waterflooded pools as well as open hole multi-lateral wells following up on the success of the 2018 program. Timing for the 2019 program is in the third quarter of 2019 to take advantage of lower drilling, completion, and equipping costs generally realized in the summer in Mannville, as well as the anticipation that heavy oil price differentials will improve through 2019. Additionally, up to 10 shallow gas recompletions are planned to be executed in late 2019, if gas prices improve, to partially offset natural gas declines in Eastern Alberta. Decommissioning expenditures will continue to be focused in the Mannville area and are expected to provide future lease rental and property tax expense reductions while maintaining regulatory compliance. In Eastern Alberta, production is forecast to grow from a range of 1,800 to 1,900 boe/d (54% oil) in 2018 to 2,200 to 2,400 boe/d (61% oil) in 2019.

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

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

2019 Exploration and Development Forecast Capital Expenditures

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

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

Perpetual expects the 2019 capital program will be funded by adjusted funds flow. Perpetual forecasts average production of 9,200 to 9,600 boe/d, with oil and NGL production growing to represent approximately 22% of the production mix. The Company expects to exit the year at over 11,500 boe/d (80% natural gas) as production ramps up again driven by the second half capital spending program targeting seasonal natural gas price optimization. This represents a reduction in average daily production in 2019 of approximately 11% relative to 2018, but includes a 16% increase in oil and NGL production.

Cash costs of $17.00 to $18.00/boe are forecast for 2019, up approximately 13% to 16% from 2018 guidance due to the impact of 11% lower forecast 2019 production on a substantially fixed operating cost base. Increased oil production in 2019 that is higher cost than compared to natural gas cash costs, is also expected to contribute to the increase in 2019 cash costs per boe.

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

Market/Pricing Point

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

(1) Net of royalties.
(2) For the 2019 calendar year, Perpetual has a costless collar on 500 bbl/d protecting a WTI floor price of US$60.00/bbl with a ceiling price of US$72.40/bbl, along with a 500 bbl/d WCS differential fixed at US$26.83/bbl.

Guidance assumptions are as follows:

	2019 Guidance
Exploration and development expenditures (*$ millions*)	**$21 - $25**
2019 cash costs (*$/boe*)	**$17.00 - $18.00**
2019 average daily production (*boe/d*)	**9,200 – 9,600**
2019 average production mix (*%*)	**22% oil and NGL**

Commodity price assumptions reflect market price levels as follows:

	2019 Guidance
2019 average NYMEX natural gas price (*US$/MMBtu*)	**$2.89**
2019 average West Texas Intermediate ("WTI") oil price (*US$/bbl*)	**$69.81**
2019 average Western Canadian Select ("WCS") differential (*US$/bbl*)	**($29.16)**
2019 average exchange rate (US$1.00 = Cdn$)	**$1.30**

Year end 2019 net debt (net of the estimated market value of the Company's TOU share investment of approximately $35 million), is forecast at $103 to $108 million, with an estimated net debt to trailing twelve months adjusted funds flow ratio of approximately 4.3 times. Current guidance is based on the following assumptions:

- Net debt at December 31, 2018 of $104 to $107 million
- Adjusted funds flow for 2019 of $22 to $27 million ($0.36/share to $0.44/share)
- Capital spending for 2019 of $21 to $25 million
- Decommissioning expenditures for 2019 of $1.5 to $2.0 million

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

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

THIRD QUARTER FINANCIAL AND OPERATING RESULTS

Capital expenditures

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Exploration and development	**4,338**	25,384	**20,922**	53,928
Other	**5**	8	**349**	60
Capital expenditures	**4,343**	25,392	**21,271**	53,988
Acquisitions	**1,261**	224	**1,871**	432
Net payments (proceeds) on dispositions	**3,080**	456	**(3,616)**	1,020
Total	**8,684**	26,072	**19,526**	55,440

Exploration and development spending by area

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
West Central	**181**	25,368	**9,430**	47,341
Eastern Alberta	**4,157**	16	**11,492**	6,587
Total	**4,338**	25,384	**20,922**	53,928

Wells drilled by area

	Three months ended September 30,		Nine months ended September 30,	
(gross/net)	**2018**	2017	**2018**	2017
West Central	**-/-**	5/4.4	**1/1.0**	11/10.4
Eastern Alberta	**3/3.0**	-/-	**6/6.0**	5/4.3
Total	**3/3.0**	5/4.4	**7/7.0**	16/14.7

Perpetual's exploration and development spending in the third quarter of 2018 was $4.3 million, 83% lower than the comparative period in 2017. Capital expenditures were directed almost entirely to Eastern Alberta and included the drilling of three (3.0 net) new heavy oil horizontal wells, along with a fourth well that was re-entered at Mannville. Two of the wells were tied-in to production at the end of the third quarter, and the remaining two came online during the first week of October. The third quarter 2018 drills were development wells targeting higher pressure areas of existing pools under waterflood, and production results to date are consistent with expectations. The fourth well was a re-entry to add three unlined laterals to an exploratory single-leg well drilled in 2017, to evaluate the application of multi-lateral drilling technology for the large resource in place in the low recovery Mannville oil pool. Initial results are positive, and the Company will continue to monitor performance. Capital was also invested in the installation of a one-megawatt electricity generator at the Mannville plant site. The project will utilize fuel gas produced from the Mannville gas plant and convert it to electricity which will be sold on the grid, effectively increasing the value of Mannville gas production. The generator was sourced from internal inventory, minimizing the net cost of the project. The power project came online in the first week of October. The economics of an expansion to a five-megawatt generating capacity is being evaluated.

Spending at the East Edson property in West Central Alberta represented just 4% of total exploration and development expenditures in the third quarter of 2018, and consisted primarily of maintenance activities associated with reconfiguring equipment for higher NGL recoveries. East Edson capital activity for the nine months ended September 30, 2018 included the drilling of one (1.0 net) Wilrich extended reach horizontal ("ERH") natural gas well and the frac and tie-in of two wells drilled in the fourth quarter of 2017. The well drilled during the first quarter is expected to be frac'd and tied-in to production during the fourth quarter of 2018 to align high initial production rates with higher anticipated winter natural gas prices.

For the nine months ended September 30, 2018, spending in Eastern Alberta consisted of a six well (6.0 net) multi-lateral horizontal drilling program, one waterflood injector well conversion, one water disposal well conversion and associated facilities on the Company's Mannville heavy oil properties. The disposal facility is working as intended, and is contributing to operating cost improvements. Two of the wells drilled during the third quarter offset a water injector well converted in December of 2017. The wells encountered high pressures and are producing at budgeted oil rates, further validating the success of the Mannville waterfloods.

During the third quarter of 2018, Perpetual spent $1.3 million to acquire the remaining 33% working interest in a Mannville heavy oil pool, adding approximately 65 boe/d of production.

Dispositions

Proceeds (payments) on dispositions

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Proceeds from dispositions of oil and gas properties	**4**	494	**12,156**	930
Proceeds from retained shallow gas marketing arrangements[1]	**–**	–	–	869
Payments on retained shallow gas marketing arrangements[1]	**(3,084)**	(950)	**(8,540)**	(2,819)
Net proceeds (payments) on dispositions	**(3,080)**	(456)	**3,616**	(1,020)

Gain (loss) on dispositions

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Proceeds from dispositions of oil and gas properties	**4**	494	**12,156**	930
Carrying amount of PP&E and E&E disposed, net of ARO	**–**	–	**(11,415)**	(8)
Realized gain (loss) from retained shallow gas marketing arrangements[1]	**–**	–	**(874)**	869
Unrealized loss on retained shallow gas marketing arrangements[1]	**–**	(2,072)	**–**	(6,592)
Gain (loss) on dispositions	**4**	(1,578)	**(133)**	(4,801)

(1) Related to the Shallow Gas Disposition.

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

On October 1, 2016, Perpetual sold 5,900 boe/d of mature shallow gas assets in east central and northeast Alberta for nominal cash consideration that also included retained marketing arrangements whereby the Company provided natural gas floor price protection at $2.58/GJ to the purchaser and retained price participation to the extent average monthly AECO prices exceed $2.81/GJ on 33,611 GJ/d through to August 31, 2018. The Company entered into marketing arrangements prior to closing to fix the cost of the floor price protection through to March 31, 2018. Realized and unrealized gains and losses on these marketing arrangements have been recognized as adjustments to gains/losses on dispositions and included as cash flows from investing activities in the consolidated statement of cash flows. During the first quarter of 2018, Perpetual fixed the cost of the floor price protection for the remaining period from April 1, 2018 to August 31, 2018 at a cost of $7.6 million. Remaining payments of $3.1 million were made during the third quarter (nine months ended September 30, 2018 – $8.5 million) related to the fixed floor price protection. The retained marketing arrangements have since expired.

Expenditures on decommissioning obligations

During the three months ended September 30, 2018, Perpetual spent $0.3 million (Q3 2017 – $0.9 million) on abandonment and reclamation projects. As part of Perpetual's focus on well and pipeline abandonment and reclamation, five reclamation certificates were received from the Alberta Energy Regulator during the third quarter of 2018 (Q3 2017 – two) which will result in the cessation of associated property tax and surface lease expenses. For the nine months ended September 30, 2018, Perpetual spent $1.2 million (2017 – $1.4 million) on abandonment and reclamation projects and received 18 reclamation certificates, compared to 29 in the prior year period. Perpetual will continue to execute its internally managed asset retirement program at Mannville in the final quarter of 2018.

Operating netbacks

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

	Three months ended September 30, 2018			Three months ended September 30, 2017		
(*$ thousands*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue(1)	**13,994**	**6,510**	**20,504**	14,921	5,104	20,026
Realized gains on derivatives(2)	**–**	**–**	**45**	–	–	665
Royalties	**(1,967)**	**(691)**	**(2,658)**	(1,841)	(773)	(2,614)
Production and operating expenses	**(1,725)**	**(3,577)**	**(5,302)**	(1,944)	(1,382)	(3,326)
Transportation costs	**(1,207)**	**(383)**	**(1,590)**	(921)	(410)	(1,331)
Total operating netback	**9,095**	**1,859**	**10,999**	10,215	2,539	13,420

	Nine months ended September 30, 2018			Nine months ended September 30, 2017		
(*$ thousands*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Total petroleum and natural gas revenue(1)	**47,902**	**16,716**	**64,618**	41,442	16,469	57,912
Realized gains on derivatives(2)	**–**	**–**	**1,784**	–	–	1,574
Royalties	**(6,545)**	**(1,766)**	**(8,311)**	(7,376)	(1,946)	(9,322)
Production and operating expenses	**(5,562)**	**(8,816)**	**(14,378)**	(6,159)	(6,402)	(12,561)
Transportation costs	**(3,531)**	**(1,048)**	**(4,579)**	(2,290)	(1,282)	(3,572)
Total operating netback	**32,264**	**5,086**	**39,134**	25,617	6,839	34,031

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

	Three months ended September 30, 2018			Three months ended September 30, 2017		
(*$/boe*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**7,695**	**1,874**	**9,569**	8,313	2,017	10,330
Total petroleum and natural gas revenue	**19.77**	**37.76**	**23.29**	19.51	27.50	21.07
Realized gains on derivatives	**–**	**–**	**0.05**	–	–	0.70
Royalties	**(2.78)**	**(4.01)**	**(3.02)**	(2.41)	(4.16)	(2.75)
Production and operating expenses	**(2.44)**	**(20.75)**	**(6.02)**	(2.54)	(7.45)	(3.50)
Transportation costs	**(1.71)**	**(2.22)**	**(1.81)**	(1.20)	(2.21)	(1.40)
Total operating netback	**12.84**	**10.78**	**12.49**	13.36	13.68	14.12

	Nine months ended September 30, 2018			Nine months ended September 30, 2017		
(*$/boe*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Boe operating netback						
Production (*boe/d*)	**9,168**	**1,797**	**10,965**	7,212	2,028	9,240
Total petroleum and natural gas revenue	**19.14**	**34.06**	**21.59**	21.05	29.75	22.96
Realized gains on derivatives	**–**	**–**	**0.59**	–	–	0.62
Royalties	**(2.62)**	**(3.60)**	**(2.78)**	(3.75)	(3.52)	(3.70)
Production and operating expenses	**(2.22)**	**(17.96)**	**(4.80)**	(3.13)	(11.56)	(4.98)
Transportation costs	**(1.41)**	**(2.14)**	**(1.53)**	(1.16)	(2.32)	(1.42)
Total operating netback	**12.89**	**10.36**	**13.07**	13.01	12.35	13.48

Production and operating expenses increased in the third quarter of 2018 due to remediation costs incurred from the Mannville produced water spill and the absence of a $0.9 million ($0.95/boe) non-recurring third-party processing fee adjustment received in the prior year period. Transportation costs were higher in the third quarter due to increased firm natural gas pipeline capacity commencing in the fourth quarter of 2017.

Perpetual's operating netback of $11.0 million ($12.49/boe) in the third quarter of 2018 decreased 18% from $13.4 million ($14.12/boe) in the comparative period of 2017. This decrease was due to the 7% decrease in production caused by natural declines at East Edson, combined with a 12% decrease in operating netback per boe. The lower operating netback per boe in the third quarter of 2018 reflected a 7% increase in realized revenue per boe due to improved crude oil and NGL pricing. Higher realized selling prices were more than offset by the associated increase in royalties, combined with higher operating costs related to the non-recurring items.

Perpetual's operating netback of $39.1 million ($13.07/boe) for the nine months ended September 30, 2018 increased 15% from $34.0 million ($13.48/boe) in the comparative period of 2017. This increase was due to the 19% increase in production, offset partially by the modest decrease in operating netback per boe.

Production

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
Natural gas (*MMcf/d*)				
Eastern Alberta	**5.2**	6.4	**5.2**	6.4
West Central	**41.7**	45.4	**50.0**	39.5
Total natural gas[(1)]	**46.9**	51.8	**55.2**	45.9
Crude oil (*bbl/d*)				
Eastern Alberta[(2)]	**1,009**	956	**937**	949
West Central	**13**	22	**28**	19
Total crude oil	**1,022**	978	**965**	968
Total NGL (*bbl/d*)[(3)]	**730**	733	**794**	627
Total production (*boe/d*)	**9,569**	10,330	**10,965**	9,240

(1) Natural gas production yielded a heat content of 1.17 GJ/Mcf (Q3 2017 – 1.17) for the three months ended and 1.17 GJ/Mcf for the nine months ended September 30, 2018 (2017 – 1.16), resulting in higher realized natural gas prices per Mcf. See "Commodity Prices" – Average Perpetual prices for selling price premium to AECO Daily Index.

(2) Primarily Mannville heavy oil.

(3) Primarily West Central liquids-rich gas.

Third quarter production averaged 9,569 boe/d, down 7% from 10,330 boe/d in the comparative period of 2017. The decrease was driven by approximately 700 boe/d of production that was shut-in at East Edson throughout the second and third quarters at the request of the Alberta Energy Regulator after the operator of record, Sequoia, filed for bankruptcy. On October 15, 2018, Perpetual submitted a property claim application to the bankruptcy trustee requesting the transfer of the four well pad operating license back to Perpetual. The bankruptcy trustee has stated they will cooperate with the application, and Perpetual anticipates that production from these wells will resume by early 2019. Compared to the second quarter of 2018, production was down 10%. The decrease was driven by natural declines in East Edson resulting from limited capital investment during 2018 in response to low AECO natural gas prices. There were no voluntary market related shut-ins of natural gas production during the third quarter.

NGL yields at East Edson were consistent with the second quarter of 2018 at approximately 17 bbls per MMcf of natural gas, an increase from 16 bbls per MMcf in the third quarter of 2017, due to the reconfiguration of plant processing equipment and higher NGL production from wells tied-in and reactivated during the first quarter of 2018.

Crude oil production in Eastern Alberta was 7% higher than the second quarter of 2018. The increased production was due to the combined impact of the Mannville heavy oil working interest acquisition and lower base declines at Mannville due to waterflood operations. At Mannville, waterflood performance continues to be a focus with base production increasing by approximately 8% throughout the year. Production from new heavy oil wells drilled did not commence until late in the quarter.

For the nine months ended September 30, 2018, production increased by 19% to 10,965 boe/d compared to 9,240 boe/d in the prior year period. Production reached peak levels in the first quarter of 2018, and has since declined as further drilling in East Edson has been deferred pending higher natural gas prices.

Production at East Edson is expected to continue to decline in the fourth quarter until the well drilled in the first quarter of 2018 is frac'd and tied in for production, and the shut-in four well East Edson pad is restarted.

Commodity Prices

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
Reference prices				
NYMEX Daily Index (*US$/MMBtu*)	**2.90**	3.00	**2.90**	3.17
AECO Daily Index (*$/GJ*)	**1.13**	1.38	**1.41**	2.19
AECO Daily Index ($/Mcf)(1)	**1.19**	1.46	**1.49**	2.31
Alberta Gas Reference Price (*$/GJ*)(2)	**1.04**	1.58	**1.22**	2.15
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**69.50**	48.20	**66.75**	49.47
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(22.25)**	(9.94)	**(21.93)**	(11.88)
WCS average (Cdn*$/bbl*)(3)	**61.90**	47.83	**57.82**	49.24
Average Perpetual prices				
Natural gas (*$/Mcf*)(1)				
AECO Daily Index	**1.19**	1.46	**1.49**	2.31
Heat content premium(4)	**0.13**	0.15	**0.16**	0.24
Market diversification contracts	**1.17**	–	**0.84**	–
Realized gains (losses) on financial and physical gas derivatives	**0.29**	1.28	**0.11**	1.09
Realized gains (losses) on prompt month price optimization	**0.05**	0.10	**0.09**	0.01
Realized natural gas price (*$/Mcf*)(5)	**2.83**	2.99	**2.69**	3.65
Percent of AECO Daily Index	**238**	205	**181**	158
Realized oil price (*$/bbl*)(5)	**48.57**	43.01	**50.06**	39.86
Natural gas liquids ("NGL") (*$/bbl*)	**56.02**	39.06	**58.19**	43.59

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.
(2) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.
(3) Derived internally using the Bank of Canada average foreign exchange rate of US$1.00 = Cdn$1.31 for the three months ended September 30, 2018 (Q3 2017 – $1.25) and $1.29 for the nine months ended September 30, 2018 (2017 – $1.31).
(4) Realized natural gas prices are at a premium to the AECO Daily Index due to higher heat content. For the three and nine months ended September 30, 2018, Perpetual received an 11% premium to the AECO Daily Index (three and nine months ended September 30, 2017 – 10%).
(5) Realized natural gas and oil prices include physical forward sales contracts for which delivery was made during the reporting period, and realized gains and losses on financial derivatives and foreign exchange contracts.

Despite increased demand due to a colder year-over-year winter, a warmer year-over-year May and September 2018, and higher liquefied natural gas ("LNG") and Mexican exports; 7.4 Bcf/d of higher United States production in the nine months ended September 30, 2018 versus the prior year period caused NYMEX natural gas prices to decrease 9% from US$3.17/MMBtu for the nine months ended September 30, 2017 to an average of US$2.90/MMBtu for the nine month period ended September 30, 2018. In comparison, the average AECO Daily Index price decreased 35% from $2.19/GJ for the nine months ended September 30, 2017 to $1.41/GJ for the nine month period ended September 30, 2018. In mid-2017, AECO prices became disconnected from the North American market as production growth in the Western Canadian Sedimentary Basin outpaced access to markets outside of Western Canada and local market demand, aggravated by the management of pipeline maintenance activities.

The increase of WTI to US$66.75/bbl for the nine month period ended September 30, 2018 from US$49.47/bbl for the nine months ended September 30, 2017 was related to the reduction in global oil inventories in 2018, stemming from the OPEC production cuts that began January 1, 2017, continued steep declines in Venezuelan production, and the pending reinstatement of sanctions on Iranian production by the United States beginning in November 2018. The WCS differential widened from an average US$11.88/bbl in the first nine months of 2017 to US$21.93/bbl in the same period of 2018, due to increased heavy oil and bitumen production predominately related to the ramp up of Suncor's Fort Hills oil sands project in Q3 2018, combined with pipeline capacity constraints that restricted access to markets outside of Western Canada.

Perpetual's realized natural gas price, including derivatives, decreased 5% to $2.83/Mcf for the third quarter of 2018 from $2.99/Mcf in the comparative period of 2017, but represented a 138% premium over the AECO Daily Index price compared to 105% in the prior year period. Realized gains on financial and physical gas derivatives, along with prompt month price optimization operations added $0.34/Mcf to the realized price in the third quarter of 2018 (Q3 2017 – $1.38/Mcf). The market diversification contract added $1.17/Mcf (Q3 2017 – nil) on the relative strength of NYMEX daily index prices compared to AECO. During the third quarter of 2018, the average heat content conversion ratio for Perpetual's natural gas production was 1.17 GJ:1 Mcf, consistent with the comparative period of 2017. Natural gas production from East Edson yields higher heat content gas compared to Perpetual's other production areas. Market diversification contract sales commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018, and pricing is based on daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) outside of Alberta that generally track North American NYMEX prices.

Perpetual's realized oil price of $48.57/bbl was 13% higher than the third quarter of 2017 and included realized losses on crude oil derivative contracts of $0.8 million ($8.96/bbl) on 750 bbl/d of production. Realized prices in the third quarter of 2017 were reduced by $3.52/bbl associated with realized hedging losses in the period.

Perpetual's realized NGL price for the third quarter of 2018 reached $56.02/bbl, up 43% from the third quarter of 2017, reflecting an increase in all NGL component prices which closely correlate with the 44% increase in WTI light oil prices over the prior year period. Perpetual's average NGL sales composition for the third quarter ended September 30, 2018 consisted of 61% condensate, comparable to the prior year period.

Revenue

($ thousands, except as noted)	Three months ended September 30, **2018**	2017	Nine months ended September 30, **2018**	2017
Petroleum and natural gas revenue				
Natural gas[1]	**11,330**	13,205	**38,035**	38,435
Oil	**5,410**	4,186	**13,963**	12,017
NGL	**3,764**	2,635	**12,620**	7,460
Total petroleum and natural gas revenue	**20,504**	20,026	**64,618**	57,912
Realized gains (losses) on derivatives[2]	**45**	665	**1,784**	1,574
Realized revenue	**20,549**	20,691	**66,402**	59,486
Unrealized gains (losses) on derivatives	**(34)**	(96)	**(5,138)**	4,279
Total revenue	**20,515**	20,595	**61,264**	63,765
Realized revenue *($/boe)*	**23.34**	21.77	**22.18**	23.58
Total revenue *($/boe)*	**23.30**	21.67	**20.47**	25.28

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

Perpetual's petroleum and natural gas ("P&NG") revenue, before derivatives, for the three months ended September 30, 2018 of $20.5 million increased 2% from the third quarter of 2017 despite a 7% decrease in average daily production. For the nine month period ended September 30, 2018, P&NG revenue increased by 12% compared to the prior year period, following the 19% increase in average daily production over the same period.

Natural gas revenue, before derivatives, of $11.3 million in the third quarter of 2018 comprised 55% (Q3 2017 – 66%) of total P&NG revenue while natural gas production was 81% (Q3 2017 – 84%) of total production. Natural gas revenue decreased 14% from $13.2 million in the third quarter of 2017, reflecting the impact of the 9% decrease in natural gas production volumes driven by natural declines following limited capital investment in East Edson during the second and third quarters of 2018. Perpetual's market diversification contract contributed $5.0 million of incremental revenue ($1.17/Mcf) over the AECO Daily Index price in the quarter ($12.7 million and $0.84/Mcf for the nine months ended September 30, 2018). For the nine month period ended September 30, 2018, natural gas revenue decreased by 1% compared to the prior year period, due primarily to the 35% decline in AECO Daily Index prices which more than offset the 20% increase in natural gas production over the same period.

Oil revenue of $5.4 million represented 26% (Q3 2017 – 21%) of total P&NG revenue while oil production was 11% (Q3 2017 – 9%) of total production. Oil revenue was 29% higher than the same period in 2017 due to the 13% increase in realized oil prices combined with the 4% increase in crude oil production. The improved WCS average prices are a function of a higher WTI US$ benchmark price and stronger US dollar, which more than offset the wider WCS differential compared to the prior year period. For the nine month period ended September 30, 2018, oil revenue increased by 16% compared to the prior year period, due primarily to the 17% increase in WCS prices with steady oil production over the same period.

NGL revenue for the third quarter of 2018 of $3.8 million represented 19% (Q3 2017 – 13%) of total P&NG revenue while NGL production was just 8% (Q3 2017 – 7%) of total Company production. NGL revenue increased by 43% over the prior year period while NGL production remained flat, reflecting a 43% increase in NGL prices compared to the prior year period. For the nine month period ended September 30, 2018, NGL revenue increased by 69% compared to the prior year period, due to the 27% increase in production combined with a 33% increase in realized NGL prices. The increase in production over the nine months ended September 30, 2017 reflected increased natural gas production at East Edson and higher NGL yields related to process optimization work at the Company's 100% owned and operated gas plant.

Realized gains on derivatives totaled $0.1 million for the third quarter of 2018, compared to gains of $0.7 million for the same period of 2017. The realized gain in the current period was comprised of $0.9 million from natural gas derivatives (Q3 2017 – $1.0 million), offset partially by losses of $0.8 million from oil derivatives (Q3 2017 – $0.3 million).

Perpetual recorded minimal unrealized losses on derivatives during the third quarter of 2018 and 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 September 30, 2018	2017	Nine months ended September 30, 2018	2017
Crown	**573**	574	**2,001**	1,806
Freehold and overriding[(1)]	**2,085**	2,040	**6,310**	7,516
Total	**2,658**	2,614	**8,311**	9,322
Crown (*% of P&NG revenue*)	**2.8**	2.9	**3.1**	3.1
Freehold and overriding (*% of P&NG revenue*)	**10.2**	10.2	**9.8**	13.0
Total (*% of P&NG revenue*)	**13.0**	13.1	**12.9**	16.1
$/boe	**3.02**	2.75	**2.78**	3.70

(1) Includes $1.3 million in gross overriding royalty payments at East Edson for the three months ended September 30, 2018 (Q3 2017 – $1.2 million) and $4.1 million for the nine months ended September 30, 2018 (2017 – $5.3 million).

Royalty expenses for the third quarter of 2018 were $2.7 million, consistent with the comparable period of 2017. Similarly, the combined average royalty rate on P&NG revenue remained consistent with the prior year period at approximately 13%.

For the nine months ended September 30, 2018, sharply lower Alberta Gas Reference prices (43% decline) and AECO Daily Index prices (35% decline) used to calculate crown and freehold natural gas royalties respectively, contributed to most of the decrease in royalty expense, despite the 20% increase in natural gas production over the same period. Pursuant to Perpetual's East Edson agreements, the partner is entitled to a gross overriding royalty equivalent to a maximum of 5.6 MMcf/d of natural gas from the East Edson property plus oil and associated NGL's on a monthly basis. The East Edson royalty is taken in kind, but calculated based on the AECO Daily Index natural gas price. As East Edson natural gas production has increased by 27% for the nine months ended September 30, 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 September 30, 2018	2017	Nine months ended September 30, 2018	2017
Production and operating expenses	**5,302**	3,326	**14,378**	12,561
$/boe	**6.02**	3.50	**4.80**	4.98

Total production and operating expenses were up 72% on a unit-of-production basis to $6.02/boe for the third quarter of 2018, compared to $3.50/boe for the comparable period of 2017. The increase was driven by remediation costs of $0.8 million ($0.91/boe) incurred from the Mannville produced water spill and the absence of a $0.9 million ($0.95/boe) non-recurring adjustment in the prior year period associated with third party processing facilities that were sold as part of the Shallow Gas Disposition. Remediation work related to the pipeline break at Mannville was completed in early October. On an absolute dollar basis, production and operating costs were up by $2.0 million, despite the 7% decrease in production, largely related to the non-recurring items noted above. West Central operating costs decreased by 4% to $2.44/boe in the third quarter of 2018 (Q3 2017 – $2.54/boe). The third quarter of 2018 also saw modestly higher well servicing requirements in the Mannville heavy oil operations which increased Eastern Alberta operating costs compared to the prior year period, while negatively affecting production volumes.

Transportation costs

($ thousands, except as noted)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Transportation costs	**1,590**	1,331	**4,579**	3,572
$/boe	**1.81**	1.40	**1.53**	1.42

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 third quarter of 2018 were $1.6 million, up 19% from the prior year period due to the increase in firm natural gas transportation commitments at East Edson to 78 MMcf/d that commenced in December 2017. Transportation costs averaged $1.71/boe at West Central compared to $2.22/boe for production from Eastern Alberta. On a unit-of-production basis, transportation costs were $1.81/boe in the third quarter, up 29% from the prior year period due to the impact of increased fixed firm capacity transportation costs against lower production. During the third quarter of 2018, the Company was not able to mitigate any of its excess firm transportation costs.

Gas over bitumen

($ thousands, except as noted)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Gas over bitumen royalty credit	**191**	353	**744**	1,965
Payments on gas over bitumen royalty financing[(1)]	**(179)**	(558)	**(878)**	(2,084)
Gas over bitumen, net of payments	**12**	(205)	**(134)**	(119)
$/boe	**0.01**	(0.22)	**(0.04)**	(0.05)

(1) At September 30, 2018, the fair value of the gas over bitumen royalty financing was estimated to be $1.8 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 third quarter of 2018, Perpetual recorded $0.2 million in gas over bitumen revenue, a 46% decrease from $0.4 million in the same period of 2017. The decrease in gas over bitumen revenue is attributable to the 34% decline in Alberta gas reference prices, combined with the annual 10% decline in deemed production.

Gas over bitumen royalty credits earned in the third quarter of 2018 funded payments of $0.2 million (Q3 2017 – $0.6 million) in relation to the 2014 monetization of Perpetual's future gas over bitumen royalty credits. As part of the arrangement, Perpetual makes monthly payments to the purchaser, which from time to time will vary from the actual gas over bitumen royalty credit received in the period due to timing differences. The monthly payment commitment expires concurrent with the gas over bitumen royalty credit, with final expiries expected to occur in June 2021.

Under IFRS, the monetization of future gas over bitumen royalty credits was recorded as a financial obligation ("Gas over bitumen royalty financing"); however, entitlement to future revenue from gas over bitumen royalty adjustments are not recorded as an asset but as revenue with the passage of time as it is earned. As such, gas over bitumen revenue will continue to be recognized separately as revenue in accordance with Perpetual's accounting policies with the monthly payments recognized as a reduction to the gas over bitumen royalty financing obligation. For purposes of this MD&A, the monthly payments have been included as a reduction to gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty adjustments. During the third quarter of 2018, the gas over bitumen royalty financing obligation was reduced by $0.3 million, comprised of payments of $0.2 million and an unrealized gain of $0.1 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 September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Lease rentals	**175**	178	**517**	547
Geological and geophysical costs	**78**	–	**78**	(22)
Lease expiries (non-cash)	**–**	784	**–**	2,602
Total exploration and evaluation	**253**	962	**595**	3,127

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

General and administrative ("G&A") expenses

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Cash G&A expense	**3,824**	3,912	**11,213**	11,670
Overhead recoveries	**(428)**	(1,062)	**(1,376)**	(2,577)
Total G&A expense	**3,396**	2,850	**9,837**	9,093
$/boe	**3.86**	3.00	**3.29**	3.60

During the third quarter of 2018, cash G&A expense was $3.8 million, a slight decrease from the prior year period of $3.9 million. Cash G&A expense increased by $0.3 million over the second quarter of 2018, due primarily to Sequoia litigation defence costs. The Company expects the majority of future defence costs will be covered by insurance. Compared to the prior year period, third quarter 2018 overhead recoveries decreased by 60% as a result of reduced capital spending, combined with a reduction in expenditures on decommissioning obligations. On a unit-of-production basis, total G&A expense of $3.86/boe for the three months ended September 30, 2018 was up 29% from the prior year period due to the impact of decreasing production. For the nine month period, G&A expense decreased from $3.60/boe in 2017 to $3.29/boe in 2018 due to the 19% increase in average daily production.

Share-based payments

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Share-based payments expense (non-cash)	**508**	906	**2,007**	3,423
$/boe	**0.58**	0.95	**0.67**	1.36

Non-cash share-based payments expense for the three months ended September 30, 2018 was $0.5 million, down 44% compared to the same period in 2017 due to a reduction in the value of outstanding share-based payment awards.

Depletion and depreciation

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands, except as noted*)	**2018**	2017	**2018**	2017
Depletion and depreciation	**8,262**	8,967	**27,169**	24,021
$/boe	**9.38**	9.44	**9.08**	9.52

Perpetual recorded $8.3 million of depletion and depreciation expense for the three months ended September 30, 2018, a decrease of 8% from $9.0 million recorded in the prior year period. The decrease reflects the 7% decline in production volumes compared to the prior year period, along with a 1% reduction in the depletion rate following the success of the Company's 2017 capital expenditure program that added proved plus probable reserves at a cost of $5.98/boe in 2017.

Impairment

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

In the third quarter of 2018, Perpetual determined that no additional capital would be spent to hold existing leases on its Waskahigan Duvernay prospect. As a result, the carrying value of the Waskahigan area was written down to its estimated recoverable amount of $1.3 million, resulting in an impairment charge of $7.2 million (Q3 2017 – nil) on E&E assets at September 30, 2018. On November 1, 2018, Perpetual sold its Waskahigan area interests to a third party for cash consideration of $1.3 million and retained a 1% gross overriding royalty to maintain exposure to future drilling conducted by the purchaser.

Finance expenses

	Three months ended September 30,		Nine months ended September 30,	
(*$ thousands*)	**2018**	2017	**2018**	2017
Cash interest expense and income				
Interest on revolving bank debt	**621**	380	**1,593**	764
Interest on TOU share margin demand loan	**130**	159	**440**	460
Interest on term loan	**911**	695	**2,729**	1,549
Interest on senior notes	**711**	764	**2,154**	3,043
Dividend income from TOU share investment	**(166)**	–	**(451)**	–
Total cash interest expense and income	**2,207**	1,998	**6,465**	5,816
Non-cash finance expense				
Amortization of debt issue costs	**247**	139	**764**	422
Accretion on decommissioning obligations	**210**	185	**625**	571
Change in fair value of gas over bitumen royalty financing	**(106)**	(653)	**(38)**	(1,859)
Change in fair value of TOU share put option margin loans	**–**	(48)	**–**	1,377
Total non-cash finance expense	**351**	(377)	**1,351**	511
Finance expenses recognized in net loss	**2,558**	1,621	**7,816**	6,327

Total cash interest expense and income of $2.2 million for the three months ended September 30, 2018 was 10% higher than the prior year period (Q3 2017 – $2.0 million) due to increased debt levels, partially offset by dividend income of $0.2 million ($0.10 per TOU share) received from the TOU share investment during the third quarter of 2018 (Q3 2017 – nil).

Total non-cash finance expense for the three months ended September 30, 2018 was $0.4 million (Q3 2017 – income of $0.4 million). A decrease in the fair value of the gas over bitumen royalty financing was recorded in both periods due to lower AECO future natural gas prices, resulting in a fair value at September 30, 2018 of $1.8 million. The change in the fair value of TOU share put option margin loans recorded in the third quarter of 2017 did not re-occur in 2018, as these loans were refinanced without embedded put option derivatives during the third quarter of 2017.

Change in fair value of TOU share investment

During the three months ended September 30, 2018, Perpetual recorded a loss of $1.2 million related to the change in fair value of the TOU share investment. This change was due to a 3% decrease in the TOU share price over the third quarter. At September 30, 2018, the Company owned 1.66 million TOU shares (December 31, 2017 – 1.67 million shares) having a quoted market value of $37.7 million (December 31, 2017 – $38.0 million).

LIQUIDITY AND CAPITAL RESOURCES

Perpetual's strategy includes maintaining a strong capital base to retain investor, creditor and market confidence to support the execution of its business plans. The Company manages its capital structure and adjusts its capital spending in light of changes in economic conditions such as depressed commodity prices, declines in the fair value of the Company's investment in TOU shares, and the risk characteristics of its underlying oil and natural gas assets. The Company considers its capital structure to include share capital, senior notes, the term loan, revolving bank debt, TOU share margin demand loan and net working capital, with value and liquidity enhanced through the ownership of TOU shares. To manage its capital structure and available liquidity, the Company may from time to time issue equity or debt securities, sell its TOU shares or other assets and adjust its capital spending to manage current and projected debt levels. The Company will continue to regularly assess changes to its capital structure and repayment alternatives, with considerations for both short term liquidity and longer term financial sustainability.

On November 7, 2018, the revolving bank debt Borrowing Limit was reduced from $60 million to $55 million by the Company's lenders with the next Borrowing Limit redetermination scheduled on or prior to May 31, 2019. The term of the revolving bank debt has not been extended and will mature on May 31, 2019. If the repayment term of the revolving bank debt is not extended at that time, all outstanding advances will become payable on May 31, 2019. The repayment term has not been extended due to uncertainties associated with the Sequoia litigation and pending the repayment of the $14.6 million unsecured senior notes that mature on July 23, 2019 (the "2019 Senior Notes"). Please refer to the "Third Quarter 2018 Highlights" section of this MD&A for additional discussion of the Sequoia litigation. The 2019 Senior Notes may be repaid prior to maturity at no penalty, upon provision of 30 days' notice to note holders.

After giving effect to the $5 million reduction in the Borrowing Limit, Perpetual had available liquidity at September 30, 2018 of $30.9 million, comprised of an unutilized Borrowing Limit of $8.9 million and the market value of its Tourmaline share investment net of the associated margin demand loan, of $22.0 million. Perpetual intends to continue the advancement of its Sequoia litigation defence while considering options available to repay the 2019 Senior Notes, including raising proceeds from the refinancing or sale of its Tourmaline share investment, or the sale or monetization of other assets. Management expects that the Company is more likely than not to be successful in defending against the claim such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in these financial statements.

Capital management

(*$ thousands, except as noted*)	**September 30, 2018**	December 31, 2017
Revolving bank debt	**42,431**	31,581
Term loan, measured at principal amount	**45,000**	45,000
TOU share margin demand loan, measured at principal amount	**15,681**	18,490
Senior notes, measured at principal amount	**32,490**	32,490
TOU share investment[1]	**(37,675)**	(37,985)
Net working capital deficiency[2]	**7,484**	16,404
Net debt[2]	**105,411**	105,980
Shares outstanding at end of period (*thousands*)[3]	**60,524**	59,263
Market price at end of period (*$/share*)	**0.31**	1.10
Market value of shares	**18,762**	65,189
Enterprise value[2]	**124,173**	171,169
Net debt as a percentage of enterprise value	**85**	62
Trailing twelve months adjusted funds flow[2]	**34,644**	31,115
Net debt to trailing twelve months adjusted funds flow	**3.0 times**	3.4 times

(1) The TOU share investment is based on the September 30, 2018 closing price per the Toronto Stock Exchange ($22.74 per share) and 1.66 million TOU shares held (December 31, 2017 – 1.67 million TOU shares held with a closing price of $22.78 per share).
(2) See "Non-GAAP measures" in this MD&A.
(3) Shares outstanding are presented net of shares held in trust.

At September 30, 2018, Perpetual had total net debt of $105.4 million, down $0.6 million from December 31, 2017, as net cash flow from operations and net proceeds from non-core asset sales exceeded capital expenditures and acquisitions during the year-to-date period. The net working capital deficiency of $7.5 million at September 30, 2018 decreased by $8.9 million from December 31, 2017, due to reduced capital expenditures during the third quarter of 2018 compared to the fourth quarter of 2017, resulting in lower payables at September 30, 2018 compared to December 31, 2017. The decrease in the net working capital deficiency was funded by a corresponding increase in revolving bank debt.

As at September 30, 2018, 60% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow improved during the nine months ended September 30, 2018 to 3.0 times at September 30, 2018 (December 31, 2017 – 3.4 times).

TOU share margin demand loan

At September 30, 2018, Perpetual had a $15.6 million TOU share margin demand loan ($15.7 million principal amount) secured by 1.66 million TOU shares. On July 31, 2018, the TOU share margin demand loan was entered into with the same lender, having similar terms and conditions as the previous TOU share margin loan. Interest rates are based on 90-day Banker's Acceptance rates plus 1.25%. Perpetual may repay a portion or the entirety of the loan at any time. Any repayment is a permanent reduction to the loan. Perpetual is required to maintain a lending ratio of less than 55% based on the ratio of the TOU share margin demand loan compared to the market value of the pledged TOU shares (the "Lending Ratio"). If at any time the Lending Ratio exceeds 55%, Perpetual is obligated to pay down the TOU share margin demand loan to restore the Lending Ratio to 40%. As at September 30, 2018, the Lending Ratio was 42% of the closing market value of the pledged TOU shares. The TOU share margin demand loan is designated as a financial liability for accounting purposes and measured at amortized cost.

During the nine months ended September 30, 2018, Perpetual sold 10,700 TOU shares at $25.97 per share and used the proceeds of $0.3 million to partially repay the TOU share margin loan.

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

In addition to the Lending Ratio requirements, the TOU share margin demand loan is subject to customary non-financial covenants. The Company was in compliance with all TOU share margin demand loan covenants as at September 30, 2018.

Revolving bank debt

As at September 30, 2018, the Company had borrowed $42.4 million (December 31, 2017 – $31.6 million) and issued letters of credit of $3.7 million (December 31, 2017 – $3.9 million) under its reserve-based revolving credit facility (the "Credit Facility"). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 2.0% and 4.5%. The effective interest rate on the Credit Facility at September 30, 2018 was 4.9%. For the period ended September 30, 2018, if interest rates changed by 1% with all other variables held constant, the impact on annual interest expense and net income (loss) would be $0.4 million (Q3 2017 – $0.3 million).

On November 7, 2018, the Borrowing Limit on the Credit Facility was reduced from $60 million to $55 million, following a reduction in the Borrowing Limit on May 7, 2018 from $65 million to $60 million, with the next semi-annual Borrowing Limit redetermination scheduled on or prior to May 31, 2019. If not extended, the Credit Facility will cease to revolve, and all outstanding advances will be repayable on May 31, 2019. As the Credit Facility now matures in less than one year, it has been presented as a current liability on the condensed interim consolidated statement of financial position as at September 30, 2018.

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

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

Term loan

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

($ thousands)	**September 30, 2018**	December 31, 2017
Balance, beginning of period	**$ 43,233**	$ –
Principal amount of term loan issued	**–**	45,000
Value allocated to warrants issued	**–**	(769)
Issue costs	**–**	(1,361)
Amortization of issue costs	**368**	363
Balance, end of period	**$ 43,601**	$ 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 demand loan lenders, and certain lands pledged to the gas over bitumen royalty financing counterparty.

At September 30, 2018, the term loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

			September 30, 2018		December 31, 2017	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 senior notes	July 23, 2019	8.75%	**14,572**	**14,521**	14,572	14,476
2022 senior notes	January 23, 2022	8.75%(1)	**17,918**	**17,305**	17,918	17,204
			$ 32,490	**$ 31,826**	$ 32,490	$ 31,680

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

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

As the 2019 senior notes now mature in less than one year, they have been presented as a current liability on the condensed interim consolidated statement of financial position as at September 30, 2018.

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

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

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

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

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

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

Equity

At September 30, 2018 there were 60.5 million common shares outstanding, net of 0.4 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended September 30, 2018 were 60.5 million (Q3 2017 – 59.2 million) and 59.9 million for the nine months ended September 30, 2018 (2017 – 57.6 million).

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

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

At November 7, 2018 there were 60.5 million common shares outstanding which is net of 0.4 million shares held in trust for employee compensation programs. In addition, the following potentially issuable common shares were outstanding as at the date of this MD&A:

(millions)	**November 7, 2018**
Share options[1]	**3.8**
Performance share rights[2]	**1.5**
Compensation awards[3]	**3.2**
Warrants[4]	**6.5**
Total	**15.0**

(1) As at September 30, 2018, all outstanding share options have an exercise price that is greater than the closing price of the Company's common shares of $0.31 per share. Excluding these options, the number of potentially issuable common shares would be nil.

(2) The performance share rights that vest and become redeemable are a multiple of the performance share rights granted, dependent upon the achievement of certain performance metrics over the vesting period. As at September 30, 2018, performance multipliers of 1.0 have been assumed for those unvested awards granted in 2017 and 2018.

(3) As at September 30, 2018, 2.0 million deferred options have an exercise price that is greater than the closing price of the Company's common shares of $0.31 per share. Excluding these deferred options, the number of potentially issuable common shares pursuant to the compensation awards would be 1.2 million.

(4) As at September 30, 2018, all outstanding warrants have an exercise price that is greater than the closing price of the Company's common shares of $0.31 per share. Excluding these warrants, the number of potentially issuable common shares would be nil.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q3 2018**	Q2 2018	Q1 2018	Q4 2017
Financial				
Oil and natural gas revenue	**20,504**	20,774	23,340	23,810
Net loss	**(12,259)**	(1,325)	(6,465)	(6,498)
Per share – basic and diluted	**(0.20)**	(0.02)	(0.11)	(0.11)
Cash flow from (used in) operating activities	**6,729**	8,435	11,198	10,953
Adjusted funds flow[1]	**5,155**	7,847	9,101	12,541
Per share – basic	**0.09**	0.13	0.15	0.21
Net capital expenditures				
Capital expenditures	**4,343**	2,031	14,897	19,047
Net payments (proceeds) on acquisitions and dispositions	**4,341**	(7,012)	926	970
Net capital expenditures	**8,684**	(4,981)	15,823	20,017
Common shares (*thousands*)				
Weighted average – basic and diluted	**60,468**	59,876	59,345	59,338
Operating				
Daily average production				
Natural gas (*MMcf/d*)	**46.9**	53.1	65.9	60.8
Oil (*bbl/d*)	**1,022**	971	900	888
NGL (*bbl/d*)	**730**	806	848	738
Total (*boe/d*)	**9,569**	10,620	12,742	11,765
Average prices				
Realized natural gas price (*$/Mcf*)[2]	**2.83**	2.62	2.65	3.22
Realized oil price (*$/bbl*)[2]	**48.57**	53.26	48.31	47.30
NGL price (*$/bbl*)	**56.02**	60.77	57.61	54.17

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

(2) Realized natural gas and oil prices include physical forward sales contracts for which delivery was made during the reporting period, and realized gains and losses on financial derivatives and foreign exchange contracts.

($ thousands, except as noted)	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Financial				
Oil and natural gas revenues	20,026	19,728	18,158	17,940
Net income (loss)	(8,082)	(7,219)	(14,172)	20,379
Per share – basic	(0.14)	(0.12)	(0.26)	0.39
Per share – diluted	(0.14)	(0.12)	(0.26)	0.37
Cash flow from (used in) operating activities	5,778	4,728	(2,289)	4,740
Adjusted funds flow[1]	8,199	5,265	5,110	3,329
Per share – basic	0.14	0.09	0.09	0.06
Net capital expenditures				
Capital expenditures	25,392	4,006	24,590	7,069
Net payments (proceeds) on acquisitions and dispositions	680	609	163	1,785
Net capital expenditures	26,072	4,615	24,753	8,854
Common shares (*thousands*)				
Weighted average – basic	59,152	59,045	54,468	52,924
Weighted average – diluted	59,152	59,045	54,468	54,678
Operating				
Daily average production				
Natural gas (*MMcf/d*)	51.8	45.1	40.7	40.3
Oil (*bbl/d*)	978	1,049	877	936
NGL (*bbl/d*)	733	665	479	467
Total (*boe/d*)	10,330	9,223	8,143	8,118
Average prices				
Realized natural gas price (*$/Mcf*)[2]	3.11	3.18	5.04	2.41
Realized oil price (*$/bbl*)[2]	43.01	43.91	31.39	38.95
NGL price (*$/bbl*)	39.06	44.28	49.70	46.99

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

(2) Realized natural gas and oil prices include physical forward sales contracts for which delivery was made during the reporting period, and realized gains and losses on financial derivatives and foreign exchange contracts.

The Company's oil and natural gas revenues, net 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. Natural gas production levels have decreased during 2018 due to reduced capital expenditures in response to depressed AECO natural gas prices, and due to the shut-in of approximately 700 boe/d of production during the second and third quarters of 2018 at East Edson associated with the Sequoia bankruptcy. Capital expenditures are typically low during the second quarter when break-up conditions in Alberta reduce access for field activities.

Commodity price risk management and sales obligations

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

The following tables provide a summary of commodity price risk management contracts outstanding at November 7, 2018:

Natural Gas

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

Term	**Volumes sold (bought) at AECO** *(GJ/d)*	**Average price** *($/GJ)*[(1)]	**Market prices** *($/GJ)*[(2)]	**Type of contract**
October 2018	10,000	2.06	1.35	Financial
October 2018 – March 2019	10,000	1.41	2.14	Financial
October 2018 – March 2019	5,000	1.40	2.14	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for October and November 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 November 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**
October 2018	5,000	(1.87)	(1.66)	Financial
October 2018	7,500	(1.80)	(1.66)	Physical
October 2018	(32,500)	(1.82)	(1.66)	Physical
November 2018 – March 2019	7,500	(1.55)	(1.55)	Physical
January 2019 – December 2019	7,500	(1.50)	(1.60)	Financial
January 2019 – December 2019	12,500	(1.54)	(1.60)	Physical
April 2019 – October 2019	5,000	(1.62)	(1.75)	Physical
April 2019 – October 2019	(10,000)	(1.64)	(1.75)	Physical
January 2020 – December 2020	15,000	(1.41)	(1.39)	Financial
January 2020 – December 2020	12,500	(1.41)	(1.39)	Physical
January 2021 – December 2021	5,000	(1.15)	(1.16)	Physical

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

Crude Oil

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

Term	**Volumes** *(bbl/d)*	**Fixed price** *(US$/bbl)*[(1)]	**Market prices** *(US$/bbl)*[(2)]	**Type of contract**
October 2018 – December 2018	250	63.74	64.80	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for October are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on November 7, 2018.

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

Term	**Volumes** *(bbl/d)*	**Floor price** *(US$/bbl)*	**Ceiling price** *(US$/bbl)*	**Market prices** *(US$/bbl)*[(1)]	**Type of contract**
October 2018 – December 2018	250	50.00	58.40	64.80	Financial
October 2018 – December 2018	250	50.00	60.00	64.80	Financial
January 2019 – December 2019	500	60.00	72.40	63.00	Financial

(1) Market prices for October are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on November 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
January 2019 – December 2019	500	(26.85)	(27.90)	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 October 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 November 7, 2018.

Foreign Exchange

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

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

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

Term	Notional (*US$/month*)	Strike rate (*US$/Cdn$*)	Market prices (*US$/Cdn$*)
October 2018	2,000,000	1.30	1.30
November 2018 – March 2019	2,500,000	1.30	1.31
April 2019 – October 2019	2,000,000	1.31	1.31
November 2019 – March 2020	2,000,000	1.29	1.30
April 2020 – October 2020	1,500,000	1.30	1.30

Natural Gas Sales Obligations

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

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

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

ACCOUNTING PRONOUNCEMENTS

Recently adopted

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

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

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

Issued but not yet adopted

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

CORPORATE GOVERNANCE

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

INTERNAL CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures

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

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

In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the quantity and recoverability of Perpetual's reserves; the timing and amount of future production; future prices as well as supply and demand for natural gas, NGLs and oil; the existence, operations and strategy of the commodity price risk management program; the approximate amount of forward sales and financial contracts to be employed, and the value of financial forward natural gas, oil and other risk management contracts; net income and adjusted funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes; operating, general and administrative ("G&A"), and other expenses; the costs and timing of future abandonment and reclamation, asset retirement and environmental obligations; the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Corporation's asset base; the Corporation's acquisition and disposition strategy and the existence of acquisition and disposition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom; Perpetual's ability to benefit from the combination of growth opportunities and the ability to grow through the capital expenditure program; expected compliance with credit facility and term loan covenants in 2018 and 2019; the retention of, and benefits to be received from holding the TOU share investment; expected book value and related tax value of the Corporation's assets and prospect inventory and estimates of net asset value; adjusted funds flow; ability to fund exploration and development; the corporate strategy; expectations regarding Perpetual's access to capital to fund its acquisition, exploration and development activities; the effect of future accounting pronouncements and their impact on the Corporation's financial results; future income tax and its effect on adjusted funds flow; intentions with respect to preservation of tax pools and taxes payable by the Corporation; funding of and anticipated results from capital expenditure programs; renewal of and borrowing costs associated with the credit facility; future debt levels, financial capacity, liquidity and capital resources; future contractual commitments; drilling, completion, facilities, construction and waterflood plans, and the effect thereof; the impact of Canadian federal and provincial governmental regulation on the Corporation relative to other issuers; Crown royalty rates; Perpetual's treatment under governmental regulatory regimes; business strategies and plans of management including future changes in the structure of business operations and debt reduction initiatives; and the reliance on third parties in the industry to develop and expand Perpetual's assets and operations.

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

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

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

PERPETUAL ENERGY INC.
Condensed Interim Consolidated Statements of Financial Position

As at	September 30, 2018	December 31, 2017
(*Cdn$ thousands unaudited*)		
Assets		
Current assets		
Accounts receivable (note 15)	$ 7,364	$ 14,069
Tourmaline Oil Corp. ("TOU") share investment (note 3)	37,675	37,985
Prepaid expenses and deposits	871	937
Fair value of derivatives (note 17)	560	1,585
	46,470	54,576
Fair value of derivatives (note 17)	372	1,506
Property, plant and equipment (note 4)	257,228	262,784
Exploration and evaluation (note 5)	28,607	46,704
Total assets	$ 332,677	$ 365,570
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 15,719	$ 31,410
Fair value of derivatives (note 17)	2,894	7,885
TOU share margin demand loan (note 8)	15,636	18,406
Revolving bank debt (note 9)	42,431	–
Senior notes (note 11)	14,521	–
Gas over bitumen royalty financing	1,086	1,152
Provisions (note 12)	2,246	2,580
	94,533	61,433
Fair value of derivatives (note 17)	304	–
Revolving bank debt (note 9)	–	31,581
Term loan (note 10)	43,601	43,233
Senior notes (note 11)	17,305	31,680
Gas over bitumen royalty financing	737	1,587
Provisions (note 12)	34,609	36,105
Total liabilities	191,089	205,619
Equity		
Share capital (note 13)	1,338,431	1,336,838
Warrants (note 13c)	923	923
Contributed surplus	44,245	44,152
Deficit	(1,242,011)	(1,221,962)
Total equity	141,588	159,951
Total liabilities and equity	$ 332,677	$ 365,570

Contingencies (note 7)

See accompanying notes to the condensed interim consolidated financial statements.

Robert A. Maitland
Director

Geoffrey C. Merritt
Director

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

(Cdn$ thousands, except per share amounts, unaudited)	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Revenue				
Oil and natural gas (note 15)	**$ 20,504**	$ 20,026	**$ 64,618**	$ 57,912
Royalties	**(2,658)**	(2,614)	**(8,311)**	(9,322)
	17,846	17,412	**56,307**	48,590
Change in fair value of derivatives (note 17)	**11**	569	**(3,354)**	5,853
Gas over bitumen royalty credit and other	**191**	363	**744**	2,061
	18,048	18,344	**53,697**	56,504
Expenses				
Production and operating	**5,302**	3,326	**14,378**	12,561
Transportation	**1,590**	1,331	**4,579**	3,572
Exploration and evaluation (note 5)	**253**	962	**595**	3,127
General and administrative	**3,396**	2,850	**9,837**	9,093
Share-based payments (note 14)	**508**	906	**2,007**	3,423
Depletion and depreciation (note 4)	**8,262**	8,967	**27,169**	24,021
Loss (gain) on dispositions (note 4a)	**(4)**	1,578	**133**	4,801
Impairment (note 5)	**7,200**	–	**7,200**	–
Loss from operating activities	**(8,459)**	(1,576)	**(12,201)**	(4,094)
Finance expense (note 16)	**(2,558)**	(1,621)	**(7,816)**	(6,327)
Change in fair value of TOU share investment (note 3)	**(1,242)**	(4,185)	**(32)**	(18,352)
Loss on disposition of gas storage facility	**–**	(700)	**–**	(700)
Net loss and comprehensive loss	**(12,259)**	(8,082)	**(20,049)**	(29,473)
Net loss per share (note 13d)				
Basic and diluted	**$ (0.20)**	$ (0.14)	**$ (0.33)**	$ (0.51)

See accompanying notes to the condensed interim consolidated financial statements.

PERPETUAL ENERGY INC.

Condensed Interim Consolidated Statements of Changes in Equity

	Share capital *(thousands)*	Share capital *($thousands)*	Warrants	Contributed surplus	Deficit	Total equity
(Cdn$ thousands unaudited)						
Balance at December 31, 2017	59,263	$ 1,336,838	$ 923	$ 44,152	$ (1,221,962)	$ 159,951
Net loss	–	–	–	–	(20,049)	(20,049)
Common shares issued (note 13)	1,191	1,200	–	(1,194)	–	6
Change in shares held in trust (note 13)	70	393	–	(643)	–	(250)
Share-based payments	–	–	–	1,930	–	1,930
Balance at September 30, 2018	**60,524**	**$1,338,431**	**$ 923**	**$ 44,245**	**$ (1,242,011)**	**$ 141,588**

	Share capital *(thousands)*	Share capital *($thousands)*	Warrants	Contributed surplus	Deficit	Total equity
(Cdn$ thousands unaudited)						
Balance at December 31, 2016	53,421	$ 1,325,705	$ –	$ 42,999	$ (1,185,991)	$ 182,713
Net loss	–	–	–	–	(29,473)	(29,473)
Common shares and warrants issued (note 13)	5,937	10,637	923	(2,804)	–	8,756
Change in shares held in trust	(78)	392	–	–	–	392
Share-based payments	–	–	–	3,423	–	3,423
Balance at September 30, 2017	**59,280**	**$1,336,734**	**$ 923**	**$ 43,618**	**$ (1,215,464)**	**$ 165,811**

See accompanying notes to the condensed interim consolidated financial statements.

PERPETUAL ENERGY INC.
Condensed Interim Consolidated Statements of Cash Flows

	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
(*Cdn$ thousands, unaudited*)				
Cash flows from (used in) operating activities				
Net loss	**$ (12,259)**	$ (8,082)	**$ (20,049)**	$ (29,473)
Adjustments to add (deduct) non-cash items:				
Depletion and depreciation (note 4)	**8,262**	8,967	**27,169**	24,021
Exploration and evaluation (note 5)	**–**	784	**–**	2,602
Share-based payments (note 14)	**508**	906	**2,007**	3,423
Unrealized change in fair value of derivatives (note 17)	**34**	96	**5,138**	(4,279)
Change in fair value of TOU share investment (note 3)	**1,242**	4,185	**32**	18,352
Loss (gain) on dispositions (note 4a)	**(4)**	1,578	**133**	4,801
Finance expenses (note 16)	**351**	(377)	**1,351**	511
Impairments (note 5)	**7,200**	–	**7,200**	–
Loss on disposition of gas storage facility	**–**	700	**–**	700
Expenditures on decommissioning obligations (note 12a)	**(252)**	(887)	**(1,158)**	(1,424)
Payments of restructuring costs (note 12b)	**(51)**	(417)	**(286)**	(2,316)
Change in non-cash working capital	**1,698**	(1,675)	**4,825**	(8,701)
Net cash from operating activities	**6,729**	5,778	**26,362**	8,217
Cash flows from (used in) financing activities				
Change in revolving bank debt, net of issue costs	**(367)**	24,839	**10,714**	29,243
Change in term loan, net of issue costs	**–**	(78)	**–**	33,671
Change in TOU share margin demand loan, net of issue costs	**(85)**	(16,898)	**(2,884)**	(22,733)
Change in senior notes, net of issue costs	**–**	(1,066)	**–**	(28,580)
Change in gas over bitumen royalty financing	**(179)**	(558)	**(878)**	(2,084)
Common shares and warrants issued	**–**	96	**6**	9,128
Shares purchased and held in trust (note 13)	**–**	(183)	**(250)**	(749)
Change in non-cash working capital	**–**	–	**–**	(216)
Net cash from (used in) financing activities	**(631)**	6,152	**6,708**	17,680
Cash flows from (used in) investing activities				
Capital expenditures	**(4,343)**	(25,392)	**(21,271)**	(53,988)
Acquisitions	**(1,261)**	(224)	**(1,871)**	(432)
Net proceeds (payments) on dispositions (note 4a)	**(3,080)**	(456)	**3,616**	(1,020)
Net proceeds on sale of gas storage facility investment	**–**	(700)	**–**	(700)
Proceeds on sale of TOU share investment (note 3)	**–**	–	**278**	5,687
Restricted cash	**–**	–	–	2,000
Change in non-cash working capital	**2,586**	14,842	**(13,822)**	19,679
Net cash used in investing activities	**(6,098)**	(11,930)	**(33,070)**	(28,774)
Change in cash and cash equivalents	**–**	–	**–**	(2,877)
Cash and cash equivalents, beginning of period	**–**	–	**–**	2,877
Cash and cash equivalents, end of period	**$ –**	$ –	**$ –**	$ –

See accompanying notes to the condensed interim consolidated financial statements.

1. REPORTING ENTITY

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

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

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

2. BASIS OF PREPARATION

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

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

These condensed interim consolidated financial statements of the Corporation were approved and authorized for issue by the Board of Directors on November 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. The average expected credit loss on the Company's trade accounts receivable was not significant as at September 30, 2018.

On January 1, 2018, the Company:

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

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

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

	Measurement Category	
Financial Instrument	**IAS 39**	**IFRS 9**
Accounts receivable	Loans and receivables at amortized cost	Amortized cost
TOU share investment	Financial assets at FVTPL	FVTPL
Accounts payable and accrued liabilities	Financial liabilities at amortized cost	Amortized cost
TOU share margin demand 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 15, using the cumulative effect method. Under this method, prior years financial statements have not been restated and the cumulative effect on net loss of the application of IFRS 15 to revenue contracts in progress at January 1, 2018 is nil. The Company's management reviewed its revenue streams and major contracts with customers using the IFRS 15 five step model and there were no material changes to net loss or timing of oil and natural gas revenue recognized.

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

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

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

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

See note 15 for additional disclosures required by IFRS 15.

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

IFRS 16 "Leases"

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

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

The Company plans to apply IFRS 16 initially on January 1, 2019 using the modified retrospective approach whereby the cumulative impact of adopting the standard will be recognized in retained earnings as at January 1, 2019 and comparative periods will not be restated. The Company will disclose additional information on the progress of the transition when it reports its fourth quarter 2018 results, and has yet to quantify the impacts of this standard.

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

	September 30, 2018		December 31, 2017	
	Shares *(thousands)*	**Amount** *($thousands)*	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of period	**1,667**	**$ 37,985**	1,847	$ 66,343
Sold	**(11)**	**(278)**	(180)	(5,687)
Unrealized change in fair value	**–**	**(32)**	–	(22,671)
Balance, end of period	**1,656**	**$ 37,675**	1,667	$ 37,985

At September 30, 2018, the Company held 1.66 million (December 31, 2017 – 1.67 million) TOU shares with a fair value of $37.7 million (December 31, 2017 – $38.0 million) based on a September 30, 2018 closing price of $22.74 per share (December 31, 2017 – $22.78 per share). Net loss for the nine month period ended September 30, 2018 included an unrealized loss of nil (2017 – $18.4 million unrealized loss) representing the change in fair value of TOU shares held during the period.

At September 30, 2018, 1.66 million TOU shares (December 31, 2017 – 1.67 million TOU shares) were pledged as security for the TOU share margin demand loan (note 8).

As at September 30, 2018, a $1.00 per share change in the market price of TOU shares would change the Company's net loss by $1.7 million.

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

	Oil and Gas Properties	**Corporate Assets**	**Total**
Cost			
December 31, 2016	$ 611,046	$ 7,182	$ 618,228
Additions	71,008	79	71,087
Acquisitions	233	–	233
Change in decommissioning obligations (note 12)	5,022	–	5,022
Dispositions	(8)	–	(8)
December 31, 2017	$ 687,301	$ 7,261	$ 694,562
Additions	20,712	349	21,061
Acquisitions	1,261	–	1,261
Change in decommissioning obligations (note 12)	(631)	–	(631)
Transfers from exploration and evaluation (note 5)	770	–	770
Dispositions	(848)	–	(848)
September 30, 2018	**$ 708,565**	**$ 7,610**	**$ 716,175**
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	(27,063)	(106)	(27,169)
September 30, 2018	**$ (451,728)**	**$ (7,219)**	**$ (458,947)**
Carrying amount			
December 31, 2017	$ 262,636	$ 148	$ 262,784
September 30, 2018	**$ 256,837**	**$ 391**	**$ 257,228**

At September 30, 2018, property, plant and equipment included $2.2 million (December 31, 2017 – $1.3 million) of costs currently not subject to depletion.

a) Dispositions

Proceeds (payments) on dispositions

($ thousands)	Three months ended September 30, **2018**	2017	Nine months ended September 30, **2018**	2017
Proceeds from dispositions of oil and gas properties	**4**	494	**12,156**	930
Proceeds from retained shallow gas marketing arrangements	**–**	–	**–**	869
Payments on retained shallow gas marketing arrangements	**(3,084)**	(950)	**(8,540)**	(2,819)
Net proceeds (payments) on dispositions	**(3,080)**	(456)	**3,616**	(1,020)

Gain (loss) on dispositions

($ thousands)	Three months ended September 30, **2018**	2017	Nine months ended September 30, **2018**	2017
Proceeds from dispositions of oil and gas properties	**4**	494	**12,156**	930
Carrying amount of PP&E and E&E disposed, net of ARO	**–**	–	**(11,415)**	(8)
Realized gain (loss) from retained shallow gas marketing arrangements	**–**	–	**(874)**	869
Unrealized gain (loss) on retained shallow gas marketing arrangements	**–**	(2,072)	**–**	(6,592)
Gain (loss) on dispositions	**4**	(1,578)	**(133)**	(4,801)

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

On October 1, 2016, Perpetual sold mature, high cost shallow gas assets in east central and northeast Alberta for nominal cash consideration and the transfer of $128.0 million of associated decommissioning obligations to the purchaser (the "Shallow Gas Disposition"). The Shallow Gas Disposition also included marketing arrangements whereby the Company provided floor price protection at $2.58/GJ to the purchaser and retained price exposure to the extent average monthly AECO prices exceed $2.81/GJ on 33,611 GJ/d through to August 31, 2018. The Company entered into marketing arrangements prior to closing to fix the cost of the floor price protection through to March 31, 2018. Realized and unrealized gains and losses on these marketing arrangements have been recognized as adjustments to gains/losses on dispositions and included as cash flows from investing activities in the consolidated statement of cash flows.

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

	September 30, 2018	December 31, 2017
Balance, beginning of period	**$ 46,704**	$ 47,159
Additions	**210**	1,948
Acquisitions	**610**	199
Dispositions	**(10,947)**	–
Impairments	**(7,200)**	–
Non-cash exploration and evaluation expense	**–**	(2,602)
Transfers to property, plant, and equipment	**(770)**	–
Balance, end of period	**$ 28,607**	$ 46,704

During the nine months ended September 30, 2018, $0.6 million (2017 – $0.5 million) in costs were charged directly to E&E expense in the consolidated statements of net loss.

Impairment of E&E assets

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

In the third quarter of 2018, Perpetual determined that no additional capital would be spent to hold existing leases on its Waskahigan Duvernay prospect. As a result, the carrying value of the Waskahigan area was written down to its estimated recoverable amount of $1.3 million, resulting in an impairment charge of $7.2 million (Q3 2017 – nil) on E&E assets at September 30, 2018. On November 1, 2018, Perpetual sold its Waskahigan area interests to a third party for cash consideration of $1.3 million and retained a 1% gross overriding royalty to maintain exposure to future drilling conducted by the purchaser.

6. CAPITAL MANAGEMENT

Perpetual's strategy includes maintaining a strong capital base to retain investor, creditor and market confidence to support the execution of its business plans. The Company manages its capital structure and adjusts its capital spending in light of changes in economic conditions such as depressed commodity prices, declines in the fair value of the Company's investment in TOU shares, and the risk characteristics of its underlying oil and natural gas assets. The Company considers its capital structure to include share capital, senior notes, the term loan, revolving bank debt, TOU share margin demand loan and net working capital, with value and liquidity enhanced through the ownership of TOU shares. To manage its capital structure and available liquidity, the Company may from time to time issue equity or debt securities, sell its TOU shares or other assets and adjust its capital spending to manage current and projected debt levels. The Company will continue to regularly assess changes to its capital structure and repayment alternatives, with considerations for both short term liquidity and longer term financial sustainability.

On November 7, 2018, the revolving bank debt Borrowing Limit was reduced from $60 million to $55 million by the Company's lenders with the next Borrowing Limit redetermination scheduled on or prior to May 31, 2019. The term of the revolving bank debt has not been extended and will mature on May 31, 2019. If the repayment term of the revolving bank debt is not extended at that time, all outstanding advances will become payable on May 31, 2019. The repayment term has not been extended due to uncertainties associated with the Sequoia litigation (see Note 7) and pending the repayment of the $14.6 million unsecured senior notes that mature on July 23, 2019 (the "2019 Senior Notes"). The 2019 Senior Notes may be repaid prior to maturity at no penalty, upon provision of 30 days' notice to note holders (See Note 11).

After giving effect to the $5 million reduction in the Borrowing Limit, Perpetual had available liquidity at September 30, 2018 of $30.9 million, comprised of an unutilized Borrowing Limit of $8.9 million and the market value of its Tourmaline share investment net of the associated margin demand loan, of $22.0 million. Perpetual intends to continue the advancement of its Sequoia litigation defence while considering options available to repay the 2019 Senior Notes, including raising proceeds from the refinancing or sale of its Tourmaline share investment, or the sale or monetization of other assets.

7. CONTINGENCIES

On August 3, 2018, the Company received a Statement of Claim that was filed by PricewaterhouseCoopers Inc. LIT ("PwC"), in its capacity as trustee in bankruptcy of Sequoia, with the Alberta Court of Queen's Bench (the "Court"), against Perpetual. The claim relates to an almost two-year-old transaction when, on October 1, 2016, Perpetual closed the Shallow Gas Disposition to an arm's length third party at fair market value at the time after an extensive and lengthy marketing, due diligence and negotiation process. This transaction was one of several completed by Sequoia. Sequoia assigned itself into bankruptcy on March 23, 2018. PwC is seeking an order from the Court to either set this transaction aside or declare it void, or damages of approximately $217 million. On August 27, 2018, Perpetual filed a Statement of Defence and Application for Summary Dismissal with the Court in response to the Statement of Claim. All allegations made by PwC have been denied and an application to the Court to dismiss all claims has been made on the basis that there is no merit to any of them and that they constitute an abuse of process. Perpetual's Application for Summary Dismissal is scheduled to be heard on November 8, 2018. Management expects that the Company is more likely than not to be successful in defending against the claim such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in these financial statements.

8. TOU SHARE MARGIN DEMAND LOAN

At September 30, 2018, Perpetual had a $15.6 million TOU share margin demand loan ($15.7 million principal amount) secured by 1.66 million TOU shares. On July 31, 2018, the TOU share margin demand loan was entered into with the same lender, having similar terms and conditions as the previous TOU share margin loan. Interest rates are based on 90-day Banker's Acceptance rates plus 1.25%. Perpetual may repay a portion or the entirety of the loan at any time. Any repayment is a permanent reduction to the loan. Perpetual is required to maintain a lending ratio of less than 55% based on the ratio of the TOU share margin demand loan compared to the market value of the pledged TOU shares (the "Lending Ratio"). If at any time the Lending Ratio exceeds 55%, Perpetual is obligated to pay down the TOU share margin demand loan to restore the Lending Ratio to 40%. As at September 30, 2018, the Lending Ratio was 42% of the closing market value of the pledged TOU shares. The TOU share margin demand loan is designated as a financial liability for accounting purposes and measured at amortized cost.

During the nine months ended September 30, 2018, Perpetual sold 10,700 TOU shares at $25.97 per share and used the proceeds of $0.3 million to partially repay the TOU share margin demand loan.

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

In addition to the Lending Ratio requirements, the TOU share margin demand loan is subject to customary non-financial covenants. The Company was in compliance with all TOU share margin demand loan covenants as at September 30, 2018.

9. REVOLVING BANK DEBT

As at September 30, 2018, the Company had borrowed $42.4 million (December 31, 2017 – $31.6 million) and issued letters of credit of $3.7 million (December 31, 2017 – $3.9 million) under its reserve-based revolving credit facility (the "Credit Facility"). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 2.0% and 4.5%. The effective interest rate on the Credit Facility at September 30, 2018 was 4.9%. For the period ended September 30, 2018, if interest rates changed by 1% with all other variables held constant, the impact on annual interest expense and net income (loss) would be $0.4 million (Q3 2017 – $0.3 million).

On November 7, 2018, the Borrowing Limit on the Credit Facility was reduced from $60.0 million to $55.0 million, following a reduction in the Borrowing Limit on May 7, 2018 from $65.0 million to $60.0 million, with the next semi-annual Borrowing Limit redetermination scheduled on or prior to May 31, 2019. If not extended, the Credit Facility will cease to revolve, and all outstanding advances will be repayable on May 31, 2019 (See Note 6). As the Credit Facility now matures in less than one year, it has been presented as a current liability on the condensed interim consolidated statement of financial position as at September 30, 2018.

The Credit Facility is secured by general, first lien security agreements covering all of the Company's assets, with the exception of the TOU shares that have been pledged as security for the TOU share margin demand loan (note 8) 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.

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

10. 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 13).

	September 30, 2018	December 31, 2017
Balance, beginning of period	**$ 43,233**	$ –
Principal amount of term loan issued	–	45,000
Value allocated to warrants issued	–	(769)
Issue costs	–	(1,361)
Amortization of issue costs	**368**	363
Balance, end of period	**$ 43,601**	$ 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 9). The term loan is secured by a general security agreement over all present and future property of the Company and its subsidiaries on a second priority basis, subordinate only to liens securing loans under the Credit Facility, TOU shares secured in favor of the TOU share margin demand loan lenders, and certain lands pledged to the gas over bitumen royalty financing counterparty.

At September 30, 2018, the term loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

11. SENIOR NOTES

			September 30, 2018		December 31, 2017	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 senior notes	July 23, 2019	8.75%	**14,572**	**14,521**	14,572	14,476
2022 senior notes	January 23, 2022	8.75%[(1)]	**17,918**	**17,305**	17,918	17,204
			$ 32,490	**$ 31,826**	$ 32,490	$ 31,680

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

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

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

The senior notes have a cross-default provision with the Company's Credit Facility (note 9). In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt and stock repurchases. The permitted amount of any restricted payment is limited to:

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

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

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

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

12. PROVISIONS

	September 30, 2018	December 31, 2017
Decommissioning obligations	**$ 35,537**	$ 37,081
Restructuring costs	**1,318**	1,604
Total provisions	**$ 36,855**	$ 38,685
Provisions – current	**$ 2,246**	$ 2,580
Provisions – non-current	**34,609**	36,105
Total provisions	**$ 36,855**	$ 38,685

a) Decommissioning obligations

The following significant assumptions were used to estimate decommissioning obligations:

	September 30, 2018	December 31, 2017
Decommissioning obligations, beginning of period	**$ 37,081**	$ 33,620
Obligations incurred	**632**	1,554
Obligations settled	**(1,158)**	(2,336)
Obligations disposed	**(380)**	–
Accretion (note 16)	**625**	775
Change in risk free interest rate	**(1,263)**	2,339
Change in estimates	**–**	1,129
Decommissioning obligations, end of period	**$ 35,537**	$ 37,081
Decommissioning obligations – current	**$ 2,043**	$ 2,243
Decommissioning obligations – non-current	**33,494**	34,838
	$ 35,537	$ 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:

	September 30, 2018	December 31, 2017
Undiscounted obligations	**$ 37,628**	$ 38,525
Average risk-free rate	**2.4%**	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)	(152)	(286)
Balance, September 30, 2018	**–**	**–**	**1,318**	**1,318**
Restructuring costs – current	–	–	203	203
Restructuring costs – non-current	–	–	1,115	1,115
Total	**$ –**	**$ –**	**$ 1,318**	**$ 1,318**

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

13. SHARE CAPITAL

	September 30, 2018		December 31, 2017	
	Shares *(thousands)*	**Amount** *($thousands)*	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of period	**59,263**	**$ 1,336,838**	53,421	$ 1,325,705
Issued pursuant to private placement (c)	**–**	**–**	5,143	8,968
Issued pursuant to share-based payment plans	**1,191**	**1,200**	887	1,728
Shares held in trust purchases (b)	**(339)**	**(250)**	(708)	(1,000)
Shares held in trust issued (b)	**409**	**643**	520	1,437
Balance, end of period	**60,524**	**$ 1,338,431**	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 14d). 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 September 30, 2018, 377,000 shares were held in trust (December 31, 2017 – 447,000).

c) Warrants and equity private placement

On March 14, 2017, the Company completed a private placement of 5.1 million equity units for gross proceeds of $9.0 million, of which $8.9 million has been allocated to share capital and $0.1 million to warrants. Each equity unit consisted of 1 common share and 0.21 warrants resulting in the issuance of 5,143,000 shares and 1,080,000 warrants. Included in the issuance were 1.6 million common shares and 0.4 million warrants issued to directors and officers of the Company or entities controlled by them, for proceeds of $2.9 million. In addition, 5.4 million warrants valued at $0.8 million were issued in connection with the term loan (note 10). 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:

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

If the volume weighted average price of Perpetual's common shares is greater than $2.34 per share for 60 consecutive calendar days, Perpetual has the option to require warrant holders to exercise all or any portion of the warrants at any time thereafter.

d) Per share information

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
(*thousands, except per share amounts*)				
Net loss – basic	**$ (12,259)**	$ (8,082)	**$ (20,049)**	$ (29,473)
Effect of dilutive securities	**–**	–	**–**	–
Net loss – diluted	**$ (12,259)**	$ (8,082)	**$ (20,049)**	$ (29,473)
Weighted average shares				
Issued common shares	**60,888**	59,610	**60,358**	57,927
Effect of shares held in trust	**(420)**	(458)	**(458)**	(355)
Weighted average common shares outstanding – basic and diluted	**60,468**	59,152	**59,900**	57,572
Net loss per share – basic and diluted	**$ (0.20)**	$ (0.14)	**$ (0.33)**	$ (0.51)

In computing per share amounts for the three months ended September 30, 2018, 0.9 million potentially issuable common shares through the share-based compensation plans (Q3 2017 – 1.7 million) and warrants were excluded as the Corporation had a net loss. In computing per share amounts for the nine months ended September 30, 2018, 1.1 million potentially issuable common shares through the share-based compensation plans (2017 – 1.1 million) and warrants were excluded as the Corporation had a net loss.

14. SHARE-BASED PAYMENTS

The components of share-based payments are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
Share options	**142**	240	**600**	744
Restricted rights	**–**	–	**–**	73
Performance share rights	**256**	225	**679**	702
Compensation awards	**110**	441	**728**	1,904
Share-based payments	**508**	906	**2,007**	3,423

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:

	September 30, 2018		December 31, 2017	
	Average exercise price ***($/share)***	**Share options** ***(thousands)***	Average exercise price *($/share)*	Share options *(thousands)*
Balance, beginning of period	**1.67**	**3,987**	1.71	2,068
Granted	**–**	**–**	1.71	2,015
Cancelled/forfeited	**1.66**	**(83)**	–	–
Expired	**5.97**	**(83)**	3.23	(96)
Balance, end of period	**1.58**	**3,821**	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*)**
$1.14 to $1.29	40	4.1	1.15	-	-
$1.30 to $1.57	1,765	2.7	1.42	883	1.42
$1.58 to $1.86	1,935	3.7	1.72	484	1.72
$1.87 to $2.00	81	1.9	2.00	61	2.00
Total	3,821	3.2	1.58	1,428	1.55

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 nine months ended September 30, 2018, the Company did not grant any additional share options.

b) Restricted rights plan

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

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

Restricted rights granted upon the exercise of performance share rights (note 14c) and deferred shares (note 14d) vest on the grant date and generally have a 30-day exercise period. No value is assigned to restricted rights issued pursuant to those plans as the value and expense has been recognized over the vesting period of the underlying performance share rights and deferred shares.

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

(thousands)	**September 30, 2018**	December 31, 2017
Balance, beginning of period	**–**	273
Granted to employees	**–**	44
Granted pursuant to exercise of performance share rights (c)	**1,008**	209
Granted pursuant to exercise of deferred shares (d)	**193**	369
Exercised for common shares	**(1,201)**	(895)
Balance, end of period	**–**	–

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 14b), at the discretion of the Board of Directors. Should participants of the performance share rights plan leave the organization other than through retirement or termination without cause prior to the vesting date, the performance share rights would be forfeited.

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

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

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

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

d) Deferred compensation awards

Deferred options

The Company has deferred option agreements in place with certain employees whereby they may be entitled to receive shares of the Company purchased on the open market by an independent trustee if they remain employees of the Company during such time and exercise their options. Deferred options generally vest evenly over 4 years, with expiry occurring 5 years after issuance. The shares purchased by the independent trustee are reported as shares held in trust (note 13b).

The following tables summarize information about the deferred options:

	September 30, 2018		December 31, 2017	
	Average exercise price *($/share)*	**Deferred options *(thousands)***	Average exercise price *($/share)*	Deferred options *(thousands)*
Balance, beginning of period	**1.68**	**2,268**	1.69	1,072
Granted	**–**	**–**	1.72	1,380
Cancelled/forfeited	**1.68**	**(220)**	1.74	(120)
Expired	**4.73**	**(42)**	2.55	(64)
Balance, end of period	**1.62**	**2,006**	1.68	2,268

	Deferred options outstanding			**Deferred options exercisable**	
Range of exercise prices	**Number of deferred options *(thousands)***	**Average contractual life *(years)***	**Weighted average exercise price *($/share)***	**Number of deferred options *(thousands)***	**Weighted average exercise price *($/share)***
$1.30 to $1.57	741	2.7	1.42	371	1.42
$1.58 to $1.86	1,224	3.7	1.72	306	1.72
$1.87 to $3.16	41	1.9	2.05	31	2.06
Total	2,006	3.3	1.62	708	1.58

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

Deferred shares

The Company also has deferred share agreements in place with directors and certain employees whereby, in the case of directors, upon retirement from the Board of Directors, or in the case of employees, over a period of two years if they remain employees of the Company during such time, may be entitled to receive at the discretion of the Board of Directors, cash, a grant of restricted rights (note 14b) 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 13b).

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 nine months ended September 30, 2018, the Company did not grant any additional deferred shares.

The following table shows changes to these awards:

(*thousands*)	**September 30, 2018**	December 31, 2017
Balance, beginning of period	**1,857**	2,197
Granted	**–**	684
Exercised in exchange for shares held in trust (note 13)	**(411)**	(520)
Exercised in exchange for restricted rights	**(193)**	(369)
Cancelled/forfeited	**(78)**	(135)
Balance, end of period	**1,175**	1,857

15. 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 nine months ended September 30, 2018, there was no impact to oil and natural gas revenues as a result of adopting IFRS 15.

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

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

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

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

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

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
Oil and natural gas revenue				
Natural gas[(1)]	**11,330**	13,205	**38,035**	38,435
Oil	**5,410**	4,186	**13,963**	12,017
NGL	**3,764**	2,635	**12,620**	7,460
Total oil and natural gas revenue	**20,504**	20,026	**64,618**	57,912

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

Included in accounts receivable at September 30, 2018 is $6.4 million of accrued oil and natural gas sales related to September 2018 production (December 31, 2017 – $8.0 million related to December 2017 production).

16. FINANCE EXPENSE

The components of finance expense are as follows:

	Three months ended September 30, 2018	2017	Nine months ended September 30, 2018	2017
Cash interest expense and income				
Interest on revolving bank debt	**621**	380	**1,593**	764
Interest on TOU share margin demand loan	**130**	159	**440**	460
Interest on term loan	**911**	695	**2,729**	1,549
Interest on senior notes	**711**	764	**2,154**	3,043
Dividend income from TOU share investment	**(166)**	–	**(451)**	–
Total cash interest expense and income	**2,207**	1,998	**6,465**	5,816
Non-cash finance expense				
Amortization of debt issue costs	**247**	139	**764**	422
Accretion on decommissioning obligations (note 12)	**210**	185	**625**	571
Change in fair value of gas over bitumen royalty financing	**(106)**	(653)	**(38)**	(1,859)
Change in fair value of TOU share put option margin loans	**–**	(48)	**–**	1,377
Total non-cash finance expense	**351**	(377)	**1,351**	511
Finance expenses recognized in net loss	**2,558**	1,621	**7,816**	6,327

17. FINANCIAL RISK MANAGEMENT

Realized gains on derivatives recognized in net loss for the nine months ended September 30, 2018 were $1.8 million (2017 – $1.6 million). The realized gains on derivatives for the nine months ended September 30, 2018 did not include the early settlement of any contracts prior to their maturity.

Natural gas contracts

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

Term	Sold/bought	Volumes (*GJ/d*)	Average price (*$/GJ*)	Fair Value (*$ thousands*)
October 2018 – March 2019	Sold	5,000	1.40	(507)

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

Term	Sold/bought	Volumes (*GJ/d*)	Average price (*$/GJ*)	Fair Value (*$ thousands*)
October 2018	Sold	10,000	2.06	218
October 2018 – March 2019	Sold	10,000	1.41	(966)

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

Term	Sold/bought	Volumes (*MMBtu/d*)	AECO-NYMEX differential (*US$/MMBtu*)	Fair Value (*$ thousands*)
October 2018	Sold	7,500	(1.80)	241
October 2018	Bought	32,500	(1.82)	(34)
November 2018 – March 2019	Sold	7,500	(1.55)	(280)
January 2019 – December 2019	Sold	12,500	(1.54)	(194)
April 2019 – October 2019	Sold	5,000	(1.62)	30
April 2019 – October 2019	Bought	10,000	(1.64)	(12)
January 2020 – December 2020	Sold	12,500	(1.41)	(115)
January 2021 – December 2021	Sold	5,000	(1.15)	166

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

Term	Sold/bought	Volumes (*MMBtu/d*)	AECO-NYMEX differential (*US$/MMBtu*)	Fair Value (*$ thousands*)
October 2018	Sold	5,000	(1.87)	9
January 2019 – December 2019	Sold	7,500	(1.50)	7
January 2020 – December 2020	Sold	15,000	(1.41)	(103)

Natural gas contracts - sensitivity analysis

As at September 30, 2018, if future natural gas prices changed by $0.25 per GJ with all other variables held constant, the fair value of derivatives and net loss for the period would change by $5.3 million. Fair value sensitivity was based on published forward AECO and NYMEX prices.

Oil contracts

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

Term	Volumes at WTI (*bbls/d*)	Fixed price (*US$/bbl*)	Fair Value (*$ thousands*)
October 2018 – December 2018	250	63.74	(274)

At September 30, 2018, the Company had entered into the following financial 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*)
October 2018 – December 2018	250	50.00	58.40	(434)
October 2018 – December 2018	250	50.00	60.00	(387)
January 2019 – December 2019	500	60.00	72.40	(684)

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

Term	Volumes at WTI (*bbls/d*)	WTI-WCS differential (*US$/bbl*)	Fair Value (*$ thousands*)
January 2019 – December 2019	250	(24.15)	196

Oil contracts - sensitivity analysis

As at September 30, 2018, if future oil prices changed by $5.00 per boe with all other variables held constant, the fair value of derivatives and net loss for the period would change by $1.0 million. Fair value sensitivity was based on published forward WTI and WCS prices.

Foreign exchange contracts

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

Term	Notional (*US$/month*)	Strike rate (*US$/Cdn$*)	Fair Value (*$ thousands*)
October 2018	1,500,000	1.30	19

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

Term	Notional (*US$/month*)	Strike rate (*US$/Cdn$*)	Fair Value (*$ thousands*)
October 2018	2,000,000	1.30	19
November 2018 – March 2019	2,500,000	1.30	169
April 2019 – October 2019	2,000,000	1.31	334
November 2019 – March 2020	2,000,000	1.29	85
April 2020 – October 2020	1,500,000	1.30	231

Foreign exchange contracts - sensitivity analysis

As at September 30, 2018, if future exchange rates changed by $0.10 US$/Cdn$ with all other variables held constant, the fair value of foreign exchange derivatives and net loss for the period would change by $5.1 million. Fair value sensitivity was based on published forward US$/Cdn$ rates.

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

	September 30, 2018	December 31, 2017
Physical natural gas contracts	**$ (705)**	$ 1,209
Financial natural gas contracts	**(835)**	1,506
Financial oil contracts	**(1,583)**	156
Financial foreign exchange contracts	**857**	–
Fixed portion of retained shallow gas marketing arrangements(1)	**–**	(929)
Non-fixed portion of retained shallow gas marketing arrangements	**–**	(6,736)
Fair value of derivatives	**$ (2,266)**	$ (4,794)
Derivative assets – current	**560**	1,585
Derivative assets – non-current	**372**	1,506
Derivative liabilities – current	**(2,894)**	(7,885)
Derivative liabilities – non-current	**(304)**	–
Fair value of derivatives	**$ (2,266)**	$ (4,794)

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

	Three months ended September 30,		Nine months ended September 30,	
	2018	2017	**2018**	2017
Unrealized gain (loss) on financial natural gas contracts	**(607)**	(57)	**(2,341)**	(3,618)
Unrealized gain (loss) on physical natural gas contracts	**(713)**	358	**(1,914)**	1,847
Unrealized gain (loss) on financial oil contracts	**251**	(397)	**(1,740)**	1,028
Unrealized gain (loss) on forward foreign exchange contracts	**1,035**	–	**857**	5,022
Unrealized change in fair value of derivatives	**(34)**	(96)	**(5,138)**	4,279
Realized gain (loss) on financial natural gas contracts	**915**	982	**2,633**	7,235
Realized gain (loss) on financial oil contracts	**(827)**	(317)	**(761)**	(1,483)
Realized gain (loss) on forward foreign exchange contracts	**(43)**	–	**(88)**	(4,178)
Change in fair value of derivatives	**11**	569	**(3,354)**	5,853

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 demand loan bear interest at a floating market rate, and accordingly, the fair market value approximates the carrying amount.

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

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

As at September 30, 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	37,675	–	37,675	37,675	–	–
Derivatives	2,064	(1,132)	932	–	932	–
Financial liabilities						
Financial liabilities at amortized cost						
TOU share margin demand loan	(15,636)	–	(15,636)	(15,680)	–	–
Revolving bank debt	(42,431)	–	(42,431)	(42,551)	–	–
Senior notes	(31,826)	–	(31,826)	–	(32,490)	–
Term loan	(43,601)	–	(43,601)	–	–	(45,000)
Fair value through profit and loss						
Derivatives	(4,330)	1,132	(3,198)	–	(3,198)	–
Gas over bitumen royalty financing	(1,823)	–	(1,823)	–	–	(1,823)

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

Forward-Looking Information

*Certain information regarding Perpetual in this report including management's assessment of future plans and operations may constitute forward-looking information or statements under applicable securities laws. The forward looking information includes, without limitation, anticipated amounts and allocation of capital spending; statements pertaining to adjusted funds flow levels, statements regarding estimated production and timing thereof; drilling, completion and development activities; infrastructure expansion and construction; prospective oil and natural gas liquids production capability; projected realized natural gas prices and adjusted funds flow; estimated decommissioning obligations; commodity prices and foreign exchange rates; and commodity price management. Various assumptions were used in drawing the conclusions or making the forecasts and projections contained in the forward-looking information contained in this report, which assumptions are based on management's analysis of historical trends, experience, current conditions and expected future developments pertaining to Perpetual and the industry in which it operates as well as certain assumptions regarding the matters outlined above. Forward-looking information is based on current expectations, estimates and projections that involve a number of risks, which could cause actual results to vary and, in some instances, to differ materially from those anticipated by Perpetual and described in the forward-looking information contained in this report. Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described under "Risk Factors" in Perpetual's Annual Information Form and MD&A for the year ended December 31, 2017 and those included in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR website (*www.sedar.com*) and at Perpetual's website (*www.perpetualenergyinc.com*). In addition, defence costs of legal claims can be substantial, even with respect to claims that have no merit and due to the inherent uncertainty of the litigation process, the resolution of the legal proceeding to which the Company has become subject could have a material effect on the Company's financial position and results of operations. Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Perpetual's management at the time the information is released, and Perpetual disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.*

Non-GAAP Measures

This report contains the terms "adjusted funds flow", "adjusted funds flow per share", "adjusted funds flow per boe", "annualized adjusted funds flow", "cash costs", "net working capital deficiency (surplus)", "net debt", "net bank debt", "operating netback" and "realized revenue" which do not have standardized meanings prescribed by GAAP. Management believes that in addition to net income (loss) and net cash flows from operating activities as defined by GAAP, these terms are useful supplemental measures to evaluate operating performance. Users are cautioned however that these measures should not be construed as an alternative to net income (loss) or net cash flows from operating activities determined in accordance with GAAP as an indication of Perpetual's performance and may not be comparable with the calculation of similar measurements by other entities.

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

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

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

Net debt and net bank debt: Net bank debt is measured as current and long-term bank indebtedness including net working capital deficiency (surplus). Net debt includes the carrying value of net bank debt, the principal amount of the term loan, the principal amount of the TOU share margin demand 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 demand loan, revolving bank debt, senior notes, and current portion of provisions.

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

Realized revenue: Realized revenue is the sum of realized natural gas revenue, realized oil revenue and realized NGL revenue which includes realized gains (losses) on financial natural gas, crude oil and foreign exchange contracts but excludes any realized gains (losses) resulting from contracts related to the Shallow Gas Disposition. Realized revenue is used by management to calculate the Corporation's net realized commodity prices, taking into account monthly settlements of foreign exchange contracts, financial crude oil and natural gas forward sales, collars and basis differentials. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices, and as such, any related realized gains or losses are considered part of the Corporation's realized price.

BOE Equivalents

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

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

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

DIRECTORS

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

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

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W. Mark Schweitzer
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BANKERS

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Bank of Nova Scotia

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

Odyssey Trust Company