2019 ANNUAL RESULTS

PERPETUAL
ENERGY

TO SHAREHOLDERS

Although this report shares Perpetual's results for 2019, it is impossible not to acknowledge the unprecedented times that have come upon us in March 2020. Layering on to the many market-access challenges Canada's oil and natural gas sector has been facing for multiple years which reached a crescendo in 2019, the world-wide coronavirus pandemic has now been the catalyst to activate massive economic contraction around the world, causing the global oil demand system to collapse. At the same instant, the Organization of Petroleum Exporting Countries ("OPEC") have decided that they will not be constraining supply to manage global supply-demand imbalances, triggering a price war over a production cut to combat the drop in demand brought on by the coronavirus. Oil prices have fallen over 50% since the start of 2020, capital markets are in a tail spin, and market uncertainty and volatility are off the charts. We expect changes in the natural gas supply and demand systems to also intensify in the short to medium term. In time new opportunities will present themselves and we will do our best to recognize those prospects and act.

Strategic decisions centered on diversifying Perpetual's revenue base helped to stabilize financial and operating results in a volatile commodity price environment for 2019. As in 2018, Perpetual's natural gas market diversification strategy and hedging activity significantly enhanced the Company's natural gas pricing relative to weak AECO hub Daily Index prices which averaged just $1.76/Mcf. Perpetual's realized average natural gas price was $2.77/Mcf, 57% better than the Daily Index benchmark. However, late in the third quarter, unexpected changes were made to TC Energy's natural gas system maintenance operating protocols such that contractual arrangements are no longer honored as a priority. As a result of the surprise change in protocols, Perpetual experienced a significant decline in the forecast future value of its market diversification contract and hedge positions with the contraction of the forward market AECO-NYMEX basis differential in both current and future periods. This was further exacerbated by delays to the anticipated start-up of new supply pipeline infrastructure in Western Canada and then the precipitous decline of NYMEX-based pricing as associated gas supply surged into an unseasonably warm winter, skewing the supply-demand balance. For now, our market diversification strategy has lost its effectiveness to shield Perpetual from weak Western Canadian natural gas prices.

In response to low AECO natural gas prices, the decision was made in early 2018 to prudently defer development of the Company's East Edson liquids-rich natural gas asset and focus investment to grow oil and natural gas liquids production and that continued through 2019. We invested in several small infrastructure projects to optimize our liquids recovery at East Edson, extended the reach of our successful waterflood operations to support base heavy oil production at Mannville, and invested in drilling more economically-attractive heavy oil projects in eastern Alberta, including at our newly established Ukalta property where we discovered an attractive heavy oil pool in the emerging Clearwater play using the progressive multi-lateral horizontal drilling technology.

The Company successfully completed the drilling, completion and tie-in of two exploratory six-leg multi-lateral heavy oil wells in the Clearwater formation at Ukalta, proving up a new core development area in Eastern Alberta. Following up encouraging initial results, we have established a meaningful land position in the Clearwater heavy oil play and, in the first quarter of 2020, we executed a four well drilling program, addressing key learnings to materially improve our results, both in terms of capital efficiency and well performance. Production from the Ukalta Clearwater play continues to ramp up, and the first six wells are currently contributing approximately 730 bbl/d to the Company's heavy oil sales volumes. We are excited about our preliminary results in the Clearwater play and poised for profitable investment when oil prices recover and stabilize.

Focused capital investment, specifically targeting liquids projects in both core operating areas, resulted in liquids production growth despite overall production declines. West Central natural gas liquid ("NGL") yields of approximately 19 bbls per MMcf of natural gas production (63% condensate) grew 14% relative to 2018 yields. Heavy oil production in Eastern Alberta grew 19% year-over-year, driven by positive results from heavy oil focused drilling at Ukalta and Mannville, and waterflood investment during the second half of 2018 and 2019.

Perpetual will work to navigate the current "double black swan" global energy system events and come out stronger and poised to bring ever-cleaner energy to society and value to stakeholders. As we have highlighted before, major transformations are underway for the global energy sector, both from the supply side and the demand side. Canada is producing an ever-cleaner energy molecule. Technology and innovation is reducing our surface footprint, enhancing water recycling and reducing emissions intensity. Clean, abundant and low cost natural gas is becoming the fuel of choice with growing electrification and the globalization of natural gas markets. As developing economies replace coal-fired electricity generation with modern, efficient and clean gas-fired generation, emissions are being reduced. Strong leadership is essential, both provincially, federally and by industry, for Canada to achieve the value potential of our world class resources and talent, and participate fully in this global energy transformation for the benefit of all Canadians.

Through creativity, flexibility and our entrepreneurial spirit, we will work to capture the inherent value of our diversified portfolio of resource-style plays for the short, medium and long term and to take advantage of a new era of opportunity. The Board of Directors and Management remain grateful for the talent and deep commitment of our team and the support of our stakeholders during these extraordinary times.

Susan Riddell Rose

SUE RIDDELL ROSE
President and Chief Executive Officer

March 24, 2020

2019 ANNUAL HIGHLIGHTS

2019 FINANCIAL AND OPERATING HIGHLIGHTS

Capital Spending, Production and Operations

- Perpetual's 2019 exploration and development capital program of $12.9 million was funded from adjusted funds flow, with investment weighted to heavy oil drilling in Eastern Alberta.
  - Spending in Eastern Alberta in 2019 was $11.7 million, and consisted primarily of a five well (5.0 net) heavy oil horizontal drilling program. At Mannville, three (3.0 net) wells were drilled in the second quarter of 2019, along with a re-entry to add two additional laterals to an existing oil well. Capital was also directed towards the Ukalta area of Eastern Alberta, where two (2.0 net) exploratory multi-lateral wells were drilled targeting the Clearwater formation. Exploration and development expenditures also included funds to acquire additional undeveloped crown lands focused on the Clearwater play in its Eastern Alberta core area. Positive results were followed up by the four (4.0 net) well drilling program initiated late in the fourth quarter. Heavy oil production for the four (4.0 net) first quarter 2020 drills has been ramping up, and is currently averaging an aggregate of 540 bbl/d. Combined with the Company's two (2.0 net) initial Clearwater discovery wells drilled in the third quarter of 2019, the Ukalta Clearwater play is currently contributing approximately 730 bbl/d to the Company's heavy oil sales volumes.
  - In response to low natural gas prices, spending in West Central in 2019 was just $1.2 million, and was primarily directed towards the installation of field compression equipment and a sweetening tower to restore several higher liquids ratio natural gas wells back to production.
- For the year ended December 31, 2019, Perpetual spent $1.7 million (2018 – $2.0 million) on abandonment and reclamation projects under the Alberta Energy Regulator's ("AER") area-based closure approach and has received 20 reclamation certificates to date (2018 – 18 reclamation certificates). Asset retirement obligation expenditures of $1.5 million are forecast in 2020, focused in Eastern Alberta.
- Production in 2019 averaged 8,988 boe/d (22% oil and NGL), a decrease of 15% from 10,594 boe/d (17% oil and NGL) in 2018. Production peaked during the first quarter of 2019 and then declined for the remainder of the year, as drilling activity at East Edson was deferred pending higher natural gas prices.
- During 2019, Perpetual shut-in an average 275 boe/d to take advantage of temporary situations where natural gas could be purchased at minimal cost to satisfy pre-sold commitments at attractive margins while retaining reserves for future production. Perpetual also shut-in operations at its Eastern Alberta Panny property during the third quarter representing approximately 300 boe/d of natural gas equivalent production. This property is anticipated to remain offline indefinitely, or until excessive property tax assessments are reduced.
- With capital spending focused on heavy oil drilling activities in Eastern Alberta, heavy oil production grew 17% to average 1,224 bbl/d in 2019 (2018 – 1,050 bbl/d).
- Perpetual's operating netback of $37.7 million ($11.50/boe) decreased 29% from $53.3 million ($13.79/boe) in 2018. The decrease was due to a 15% decline in production combined with the 18% decrease in realized revenue, which was the result of lower realized natural gas and NGL prices of 9% and 23%, respectively.
- The Company recorded zero reportable spills, zero lost time injuries, and zero vehicle incidents in 2019, improving upon its notably exemplary environment, health and safety record. The Workers Compensation Board ranked Perpetual number 1 out of 265 peer companies in 2019.

Financial Highlights

- Realized revenue was $73.6 million, down 18% from the prior year as a result of the 15% decrease in production combined with a 3% decrease in realized revenue per boe. The market diversification contract added $0.64/Mcf (2018 – $1.02/Mcf) on the relative strength of daily index prices at the five downstream markets compared to the AECO Daily Index. In response to TC Energy's changes to maintenance operating protocols that were implemented early in the fourth quarter, Perpetual modified its market diversification contract to shift the pricing point back to AECO for the December 2019 to October 2020 period, and recorded a realized gain of $2.7 million ($0.17/Mcf). For the year ended December 31, 2019, Perpetual recorded $0.8 million of realized losses on derivatives, comprised of $3.4 million of gains on natural gas hedges which were more than offset by losses of $4.2 million from crude oil and NGL hedges.
- Net loss for 2019 was $94.0 million ($1.56/share), up from $20.4 million in 2018 ($0.34/share). The net loss was negatively impacted by the $21.9 million unrealized loss on derivatives (2018 – unrealized gain of $5.7 million) in addition to impairment losses of $47.1 million which were recognized in 2019 (2018 – $7.2 million), reflecting the decrease in forward natural gas pricing during 2019. These changes were partially offset by an unrealized loss of $3.2 million recognized in 2019 related to the change in fair value of the TOU share investment, compared to an unrealized loss of $9.6 million recognized in the prior year.
- Net cash flow from operating activities was $17.8 million compared to $31.5 million in 2018. The decrease was driven by lower production of 15%, as total Company realized revenue per boe of $22.43/boe was only 3% lower than the prior year (2018 – $23.07/boe) with the increased weighting of oil and NGL in the production mix.
- For the year ended December 31, 2019, adjusted funds flow was $14.5 million ($0.24/share), down $15.6 million (52%) from $30.2 million ($0.50/share) in 2018 as the impact of the 15% year-over-year decrease in production combined with lower natural gas and NGL prices outweighed the 2% decrease in cash costs and increased heavy oil production.

- At December 31, 2019, Perpetual had total net debt of $118.1 million, up $5.5 million (5%) from December 31, 2018. The increase was due primarily to a $3.2 million decrease in the fair value of the TOU share investment during 2019, combined with an incremental $1.1 million of 2022 Senior Notes that were issued in connection with the early redemption of the 2019 Senior Notes in the second quarter. Revolving bank debt increased by $5.0 million during 2019 to $47.6 million at December 31, 2019 due to a $5.0 million repayment of the TOU share margin demand loan during the year.

SEQUOIA LITIGATION

On January 13, 2020, the Court of Queen's Bench (the "Court") issued its written decision related to the Statement of Claim filed on August 3, 2018 against Perpetual and its President and Chief Executive Officer ("CEO") with respect to the Company's disposition of shallow gas assets in Eastern Alberta to an unrelated third party on October 1, 2016 (the "Sequoia Litigation"). The decision dismissed and struck all claims against the Company's CEO and all but one of the claims filed by PwC in its capacity as trustee in bankruptcy (the "Trustee") against Perpetual. The Court did not find that the test for summary dismissal relating to whether the transaction was an arm's length transfer for purposes of section 96(1) of the Bankruptcy and Insolvency Act (the "BIA") was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim can continue against Perpetual. The Trustee filed a notice of appeal with the Court of Appeal of Alberta, contesting the decision, and Perpetual filed a similar notice of appeal contesting the BIA claim portion of the decision. The appeal proceedings are scheduled to be heard in December 2020.

On January 28, 2020, the Court of Appeal issued its decision with respect to Perpetual's application for security for costs, requiring the Trustee to post security with the Court of Appeal in the amount of $0.2 million. Applications have been filed by the Trustee to appeal the security for costs decision and alter the reasons for the decision. The Court of Appeal is scheduled to hear these applications in June 2020.

On February 25, 2020, Perpetual filed a new application with the Court to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the transaction nor caused to be insolvent by the transaction. Applications for security for costs for future litigation were also filed at that time. The Court is scheduled to hear these applications in June 2020.

Management expects that the Company is more likely than not to be successful in defending against the Sequoia Litigation such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in Perpetual's financial statements.

2019 STRATEGIC PRIORITIES

During 2019, progress was made to advance Perpetual's top four strategic priorities for 2019 which include:

1. Improve balance sheet and manage risk;
2. Maximize value of Greater Edson liquids-rich gas;
3. Grow value of Eastern Alberta portfolio; and
4. Advance high impact, diversifying new ventures.

Improve balance sheet and manage risk

- Perpetual's market diversification contract contributed $9.9 million of incremental revenue during the year, an uplift of $0.64/Mcf on the relative strength of the daily index prices at the five downstream markets compared to the AECO Daily Index. The 40,000 MMBtu/d market diversification contract effectively shifts the sales point to a basket of five North American natural gas hub pricing points (Chicago, Malin, Dawn, Michcon and Empress), diversifying the Company's natural gas price exposure from AECO.
- In the third quarter of 2019, Perpetual extended the term of its market diversification contract by two years. From November 1, 2022 to October 31, 2024, Perpetual will sell 40,000 MMBtu/d at AECO and receive Dawn, Emerson and Malin daily index prices less US$0.0775/MMBtu and transportation costs from AECO to the market price point.
- In late September, Perpetual expected significant tightening in AECO basis relative to other North American markets to result from proposed changes to TC Energy's NGTL natural gas maintenance operating protocols that were implemented in early October. In response, Perpetual modified its 40,000 MMBtu/d market diversification contract to shift its pricing point back to AECO for the December 2019 to October 2020 period. As a result, Perpetual recorded a realized gain on derivatives of $2.7 million related to the market diversification contract in the third quarter.
- In order to protect a base level of adjusted funds flow, Perpetual had commodity price contracts in place for multiple components of oil and natural gas sales and currency which resulted in net realized losses on financial derivatives of $0.8 million in 2019.
- Exploration and development capital spending of $12.9 million and expenditures on decommissioning obligations of $1.7 million was fully funded by $14.5 million of adjusted funds flow.
- Commencing in the fourth quarter, general and administrative costs were reduced by approximately $3.5 million annually following a 25% reduction in the Company's corporate employee head count, a reduction in savings plan compensation and a further 20% reduction for certain remaining employees, including the majority of the executive leadership team.
- On June 11, 2019, the Company fully repaid $14.6 million of 2019 Senior Notes in advance of their July 23, 2019 maturity date. An additional $15.7 million 2022 Senior Notes were issued to holders of 2019 Senior Notes that elected to participate in the senior note refinancing, representing a 7.5% premium in the principal amount outstanding. The Company now has a total of $33.6 million of 8.75% senior unsecured notes due January 23, 2022.
- Perpetual voluntarily repaid $5.0 million of its TOU share margin demand loan secured by the Company's 1.66 million TOU shares throughout the year. Additionally, in December 2019, Perpetual sold 656,773 TOU shares at an average price of $14.78 per share for net

proceeds of $9.7 million and repaid the remaining TOU share margin demand loan to reduce the balance outstanding to $0.1 million at December 31, 2019. Perpetual received dividend income of $0.8 million in the year, more than offsetting interest on the TOU share margin demand loan of $0.4 million. The market value of the 1.0 million TOU shares held at December 31, 2019 was $15.2 million ($15.22/share) compared to $28.1 million (1.66 million shares at $16.98/share) at December 31, 2018.

- In January 2020, the Company sold its remaining 1.0 million TOU shares for net cash proceeds of $14.3 million (the "TOU Share Proceeds"). Net proceeds were used to repay the remaining $0.1 million principal amount outstanding on the TOU share margin demand loan with the balance used to repay a portion of the Credit Facility.
- As at December 31, 2019, the Company's Credit Facility had a Borrowing Limit of $55.0 million (December 31, 2018 – $55.0 million) under which $47.6 million was drawn (December 31, 2018 – $42.6 million) and $2.3 million of letters of credit had been issued (December 31, 2018 – $3.7 million). On December 24, 2019, Perpetual's syndicate of Credit Facility lenders completed their semi-annual borrowing base redetermination, reducing the Borrowing Limit from $55 million to $45 million on January 22, 2020, with the maturity date remaining at November 30, 2020.
- Perpetual ended the year with total net debt of $118.1 million, 5% ($5.5 million) higher than December 31, 2018. Free cash flow of $1.6 million was fully utilized to fund decommissioning obligations and restructuring provisions. In addition, the fair value of the Company's TOU share investment decreased by $3.2 million during 2019 and an incremental $1.1 million of 2022 Senior Notes were issued in connection with the early redemption of the 2019 Senior Notes in the second quarter.
- As at December 31, 2019, 67% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow increased to 8.1 times at December 31, 2019 (December 31, 2018 – 3.7 times).
- Perpetual had available liquidity at December 31, 2019 of $20.2 million, comprised of $5.1 million of available borrowings under the Credit Facility and the $15.2 million TOU share investment market value net of the associated $0.1 million TOU share margin demand loan. After giving pro forma effect to the reduced $45 million Borrowing Limit effective on January 22, 2020, and the TOU Share Proceeds, Perpetual had available liquidity at December 31, 2019 of $9.2 million.
- All but one of the claims filed by PwC with respect to the Sequoia Litigation were dismissed or struck by the Court of Queen's Bench in an order granted February 14, 2020. These included the Trustee's claims on the grounds of oppression, public policy, statutory illegality and equitable rescission and the Trustee's claims against Perpetual's CEO for breach of fiduciary duty and breach of duty of care. The Court did not find that the test for summary dismissal relating to whether the transaction was an arm's length transfer for purposes of section 96(1) of the BIA was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim can continue against Perpetual. In addition, the application of Sue Riddell Rose to dismiss all of the Trustee's claims against her, including the BIA claim, was granted. Both PwC and Perpetual are contesting the relevant elements of the decision through the Court of Appeal of Alberta. The appeal proceedings are scheduled for December 2020.
- On January 28, 2020, the Court of Appeal issued its favorable decision with respect to the application Perpetual filed late in the third quarter of 2019 for security for costs of the appeal, requiring the Trustee to post security with the Court of Appeal in the amount of $0.2 million. Applications have been filed by the Trustee to appeal the security for costs decision and alter the reasons for the decision. The Court of Appeal is scheduled to hear these applications in June 2020.
- On February 25, 2020, Perpetual filed a new application with the Court to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the transaction nor caused to be insolvent by the transaction. Applications for security for costs for future litigation were also filed at that time. The Court is scheduled to hear these applications in June 2020.

Maximize value of Greater Edson liquids-rich gas

- Driven by the successful Wilrich formation development drilling program in 2017 and early 2018, production in West Central Alberta peaked during the first quarter of 2018 at 11,076 boe/d and has gradually declined with the suspension of the drilling program to preserve value during this period of very low and volatile prices in Western Canada related to restrictions on TC Energy's system for maintenance and debottlenecking activities and lack of new pipeline egress out of the province.
- Spending on East Edson liquids-rich gas drilling was entirely deferred in 2019. Modest spending of just $1.2 million in the first quarter of 2019 finished the installation of field compression and a sweetening tower and was directed towards compressor optimization work and non-operated facility turnaround costs at the Rosevear plant.
- Due to deferred capital spending, production in West Central Alberta was 18% lower than 2018 at 7,176 boe/d, comprising 80% of total Company production (2018 – 82%). Perpetual temporarily shut-in an annual average 275 boe/d of East Edson production to take advantage of short-term situations when natural gas could be purchased at minimal cost to satisfy pre-sold volume commitments at attractive margins, resulting in an increase in realized revenue of $0.05/Mcf ($0.7 million) while retaining reserves for future production.
- NGL yields at East Edson were 18.6 bbls per MMcf (63% condensate) in 2019, up 14% from 2018, reflecting the infrastructure modifications made in the first quarter of 2019.
- West Central production and operating expenses were effectively flat at $7.2 million but up 22% on a unit-of production basis to $2.74/boe in 2019 (2018 – $2.25/boe) due to the impact of declining natural gas production against a relatively fixed cost base. Unit operating costs continued to reflect top quartile performance driven by the streamlined nature of the operations at the Company's owned and operated West Wolf plant at East Edson.
- On a unit-of-production basis, royalties increased 17% year-over-year, in step with the 18% increase in the average AECO Daily Index price relative to 2018. Crown royalties increased modestly with higher Alberta Reference prices and as several wells shifted to higher royalty rates. As East Edson production decreased in 2019, the fixed volume nature of the gross overriding royalty, equivalent to a maximum 5.6 MMcf/d of natural gas and associated NGL production, resulted in an increased expense as a percentage of revenue and on a unit-of-production basis.

- Transportation costs were reduced by $0.4 million to $4.2 million in 2019. On a unit-of-production basis, transportation costs were 10% higher due to increased unutilized demand charges resulting from lower natural gas sales volumes.
- Operating netbacks in West Central were $10.70/boe (2018 – $14.24/boe), driven primarily by the decrease in the top line revenue contributed by the Company's natural gas market diversification contract combined with lower production driving higher unit operating costs and higher royalties and transportation costs per boe.
- East Edson represented 89% (2018 – 90%) of total proved plus probable reserves at year-end 2019 as detailed in the independent reserve report prepared by McDaniel and Associates Consultants Ltd ("McDaniel"). Although the drilling program at East Edson was suspended in 2019 due to low forward natural gas prices at AECO, technical reserve additions related to stronger than forecast well performance and improved liquids recovery drove positive reserve additions of 1.4 MMboe partially offsetting production of 2.6 MMboe. On a proved plus probable basis, estimated future development costs ("FDC") decreased by $0.8 million to $328.6 million, including 66 (63.3 net) undeveloped locations (2018 – 63.3 net locations) in the total proved plus probable eight-year development plan.
- The Company continues to monitor production from a competitor's lower Mannville Ellerslie horizontal well drilled in late 2016 to evaluate the economic viability of this liquids-rich natural gas zone as a secondary development target at East Edson. Perpetual has 49 gross (40.2 net) sections at East Edson in the prospective play fairway. Other secondary development targets at East Edson, including the Cardium, Second White Specks, Viking, Notikewin, Falher and Rock Creek formations, continue to be important for future prospectivity. Capital originally budgeted for a strategic secondary zone test was deferred due to lower forward commodity price forecasts.
- A water management strategy, including the conversion of an existing vertical well for water injection, was implemented to reduce trucking and related costs, maximize water recycling and minimize fresh water intake.
- Perpetual's maintains a Methane Reduction Retrofit Compliance Plan designed to lower methane emissions in accordance with Directive 60 of the Alberta Energy Regulator. Perpetual continued to advance its methane emissions reduction strategy through inventory and assessment of all pumps and pressure and level controllers at East Edson. In 2018, 153 controllers were replaced with low bleed controllers reducing emissions by 10,700 tonnes per year, the equivalent of taking 2,300 cars off the road annually. In addition in 2018 and 2019 Perpetual shut-in various field equipment which eliminated over 21,000 tonnes of CO2e GHG emissions annually. Perpetual is a founding member and is participating in advancing new technologies and research through the Natural Gas Innovation Fund ("NGIF"). Work is underway with Canadian Emissions Reduction Innovation Network ("CERIN") to advance a methane emissions reduction technology research project jointly funded by NGIF, CERIN and Perpetual at the Edson West Wolf gas plant.
- The Company recorded zero reportable spills, zero lost time injuries, and zero vehicle incidents in its West Central Alberta core operating area.
- Close to $0.6 million was spent on abandonment and reclamation work in West Central in 2019, including well abandonments, pipeline discontinuations and abandonments, and third party environmental spending as well as reclamation work. Perpetual received 4 reclamation certificates from the Alberta Energy Regulator ("AER") related to asset retirement obligation spending in prior periods which enable reduced property tax and surface lease rental costs going forward.

Grow value of Eastern Alberta portfolio

- Exploration and development capital expenditures in Eastern Alberta during 2019 totaled $11.7 million.
- At Mannville, the Company took advantage of dry early spring conditions to accelerate capital activity which included the drilling and completion of three (3.0 net) single leg horizontal heavy oil wells and one re-entry to add two additional lateral legs to an existing heavy oil well. Spending also included the installation of automated leak detection monitoring equipment at several water transfer and water injection pipelines in the Mannville area. Spending also included maintenance activities on electricity generators installed at the Mannville plant site to convert natural gas to electricity sales.
- Perpetual continued to focus on waterflood implementation and optimization at Mannville through 2019 and recognized the positive impact of the waterflood through an overall reduction in base decline rates and improved reserve recovery. Additional injection conversion and infrastructure projects are planned in the future to optimize reserve recovery and value.
- At Ukalta, two (2.0 net) initial exploratory wells were drilled, completed and tied-in during the third quarter. Preparatory costs and preliminary spending for the four (4.0 net) well winter drilling program were also recorded late in the fourth quarter. The Company drilled an additional four (4.0 net) multi-lateral horizontal wells in the first quarter of 2020 at Ukalta, proving additional scope to the play of up to 51 unbooked drilling locations within the lower Clearwater sand. The new wells were drilled in the first quarter of 2020 using an oil-based mud system to reduce formation damage and improve wellbore inflow.
- Production in Eastern Alberta decreased 2% relative to 2018 to 1,812 boe/d (2018 – 1,857 boe/d), however, heavy oil production increased 19%, bringing the 2019 Eastern Alberta production split up to 67% heavy oil (2018 – 55%). The strong growth in crude oil production in Eastern Alberta reflected strong waterflood response reversing natural declines in several heavy oil pools, and production additions from drilling activity after spring break-up at Mannville and Ukalta which commenced production near the end of the third quarter.
- Natural gas production in Eastern Alberta averaged 3.6 MMcf/d, down 29% from 2018, due to deferred spending on shallow gas recompletion activity given low natural gas prices and the shut-in of 1.8 MMcf/d (300 boe/d) of production at the Company's Panny property during the third quarter. Perpetual expects this property to remain offline indefinitely, or until excessive property tax assessments are reduced.
- The one-megawatt electrical generation project at the Mannville plant site contributed $0.2 million to Eastern Alberta operating netbacks in 2019. Approximately 250 Mcf/d of fuel gas produced from the Mannville gas plant is converted to electricity and sold to the grid, increasing the value of Mannville gas production.
- Production from heavy oil wells of 0.5 MMboe was more than offset by an increase of 1.2 MMboe to proved plus probable reserves related to the positive impact of the heavy oil discovery at Ukalta, development drilling and waterflood performance at Mannville during 2019. As

evaluated by McDaniel, total proved plus probable heavy oil reserves were up 15% to 5.4 MMboe at December 31, 2019. While Eastern Alberta heavy oil reserves account for just 8% of the Company's total proved plus probable reserves, these higher netback reserves at forecast commodity prices represent 23% of the net present value using a 10% discount rate ("NPV10") of Perpetual's proved plus probable reserves using the Consultant Average price forecast.

- On a proved plus probable basis, the FDC required to convert proved plus probable non-producing and undeveloped eastern Alberta heavy oil reserves to proved producing reserves increased $13.7 million to $29.0 million, including 24 (24.0 net) undeveloped drilling locations in the total proved plus probable category, an increase of eight locations from year-end 2018.
- Eastern Alberta production and operating expenses decreased $0.9 million in 2019 to $11.1 million ($16.84/boe), an 8% reduction relative to 2018 (5% on a unit-of production basis). This relative decrease reflected remediation and additional water hauling costs of $1.0 million incurred in the third and fourth quarters of 2018 from the Mannville produced water spill.
- Operating netbacks in Eastern Alberta were $15.89/boe, 125% higher than in 2018 largely driven by a 34% increase in revenue per boe. Canadian oil price differentials improved significantly in 2019 due to the implementation of production curtailments by the Government of Alberta. Perpetual's oil production is not subject to curtailment as its total production is below the designated curtailment production level.
- Perpetual continued to advance its methane emissions reduction strategy at Mannville and Ukalta.
- The Company recorded zero reportable spills, zero lost time injuries, and zero vehicle incidents in Eastern Alberta. A state of the art web-based leak detection system that continuously monitors pipeline flow using artificial intelligence throughout the Company's heavy oil operations was fully installed in the first quarter of 2019.
- Perpetual spent $1.1 million on decommissioning obligations in Eastern Alberta under the AER's area-based closure program for 2019, including well abandonments, pipeline discontinuations and abandonments, environmental spending as well as reclamation work primarily at Mannville. Perpetual received 16 reclamation certificates from the AER which will reduce property tax and surface lease expenses going forward.

Advance high impact, diversifying new ventures

- Perpetual continued reservoir modelling and simulation work to progress the opportunity for bitumen extraction in the Bluesky formation at Panny. Commercial development scoping of this large bitumen-in place resource is underway to evaluate the merits of further pilot spending. Perpetual is in negotiation with two parties for two separate follow-on pilots in two different pools in Panny. These pilots are being designed and evaluated for potential implementation in the first quarter of 2021.

YEAR-END 2019 RESERVES

Reserve Highlights

To preserve value during the low natural gas price environment in 2019, Perpetual limited capital spending on natural gas assets, executing a capital program funded through 2019 adjusted funds flow with investment weighted to heavy oil drilling and waterflood activities. Strong performance of the base assets resulted in 4% growth in proved and probable reserves year-over-year excluding production. Proved and probable reserves in the Company's Eastern Alberta Heavy Oil properties grew 10% excluding production, while East Edson natural gas and NGL reserves grew 2% excluding production, bringing Perpetual's year-end reserves just one percent lower to 67.1 MMboe, comprised of 17% oil and NGL (2018 – 67.9 MMboe, 15% oil and NGL).

The quality of Perpetual's assets and positive momentum to drive operational and execution excellence in its core operating areas are demonstrated by the highlights below:

- Total proved plus probable reserves were 67.1 MMboe at December 31, 2019, adding proved plus probable reserves of 2.4 MMboe to replace 74% of 2019 production of 3.3 MMboe with total net capital spending of $12.9 million. The increase in proved plus probable reserves was driven by strong well performance at East Edson combined with positive waterflood response and additions from successful heavy oil drilling programs.
- Total proved producing reserves were 16.0 MMboe at December 31, 2019, down 7% from year-end 2018 and proved plus probable producing reserves were 19.8 MMboe at December 31, 2019, down 9% from year-end 2018 and represented 30% of total proved plus probable reserves. Proved reserves represented 60% of the Company's total proved plus probable reserves.
- East Edson represents 89% (2018 – 90%) of total proved plus probable reserves at year-end 2019. The drilling program at East Edson was suspended in 2019 due to low forward natural gas prices at AECO, however, technical reserve additions related to stronger than forecast well performance and improved liquids recovery drove reserve additions that partially offset production.
- Net positive technical revisions of 1.5 MMboe related to performance on a proved plus probable basis were recorded in 2019. Positive technical revisions of 1.1 MMboe were attributed to improved performance of existing wells in both West Central and Eastern areas and 0.4 MMboe were related to increases in reserve assignments relating to drilling locations in the East Edson area.
- Drilling of 2.0 net exploratory wells in the new Ukalta area resulted in additions of 549 Mboe on a total proved basis and 736 Mboe on a total proved plus probable basis.
- Production from heavy oil wells at Mannville of 0.45 MMboe was offset by increases of 0.45 MMboe to proved plus probable reserves mainly related to the positive results of development drilling in 2019. While Mannville heavy oil reserves account for just 7% of the Company's total proved plus probable reserves, these higher netback reserves at forecast commodity prices represent 18% of the NPV10 value of Perpetual's proved plus probable reserves.

- Exploration and development capital spending of $12.9 million in 2019, largely focused on heavy oil projects, resulted in finding and development ("F&D") costs of $10.54/boe on a proved plus probable basis, including changes in FDC.
- Based on an equal weighting of three consultant average price (McDaniel, GLJ, Sproule) forecasts (the "Consultant Average Price Forecast") used by McDaniel, the net present value ("NPV") of Perpetual's total proved plus probable reserves (discounted at 10%) before income tax, was $297.3 million (2018 – $361.3 million). The decrease related primarily to a decrease in the independent reserve evaluators' forecast for natural gas prices at year-end 2019 as compared to the prior year. The inclusion this year of all abandonment, decommissioning and reclamation obligations had an impact of reducing value by $11.9 million, which reflects the additional obligations for non-reserve well costs and facility and pipeline costs that had not been included in the reserve report in prior years.
- Perpetual's reserve-based net asset value ("NAV") (discounted at 10%) at year-end 2019 based on the Consultant Average Price Forecast, is estimated at $200.5 million ($3.27 per share) as compared to $276.6 million ($4.59 per share) at year-end 2018, primarily due to lower forecast natural gas prices.

Reserves Summary

Working interest reserves included herein refer to working interest reserves before royalty deductions. Reserves information is based on an independent reserves evaluation report prepared by McDaniel with an effective date of December 31, 2019 (the "McDaniel Report"), and has been prepared in accordance with National Instrument 51-101 ("NI 51-101") using the Consultant Average Price Forecast. Complete NI 51-101 reserves disclosure including after-tax reserve values, reserves by major property and abandonment costs are included in Perpetual's Annual Information Form ("AIF"), which is available on the Company's website at www.perpetualenergyinc.com and SEDAR at www.sedar.com.

Perpetual's reserves at December 31, 2019 are summarized below:

Working Interest Reserves at December 31, 2019[(1)]

	Light and Medium Crude Oil (*Mbbl*)	Heavy Oil (*Mbbl*)	Conventional Natural Gas (*MMcf*)	Natural Gas Liquids (*Mbbl*)	Oil Equivalent (*Mboe*)
Proved Producing	16	2,177	75,183	1,324	16,047
Proved Non-Producing	–	106	2,035	8	453
Proved Undeveloped	–	1,177	124,331	1,898	23,797
Total Proved	**16**	**3,460**	**201,549**	**3,230**	**40,298**
Probable Producing	4	586	17,219	305	3,765
Probable Non-Producing	–	21	6,838	83	1,244
Probable Undeveloped	–	1,046	109,652	2,429	21,750
Total Probable	**4**	**1,653**	**133,710**	**2,817**	**26,759**
Total Proved plus Probable	**21**	**5,113**	**335,259**	**6,047**	**67,057**

(1) May not add due to rounding.

Total proved reserves at December 31, 2019 account for 60% (2018 – 63%) of total proved plus probable reserves. Proved producing reserves of 16.0 MMboe comprise 40% (2018 – 41%) of total proved reserves. Proved plus probable producing reserves of 19.8 MMboe represent 30% (2018 – 32%) of total proved plus probable reserves.

The table below summarizes the FDC estimated by McDaniel by play type to bring non-producing and undeveloped reserves to production.

Future Development Capital[(1)]

($ millions)	2020	2021	2022	2023	2024	Remainder	Total
Eastern Alberta Shallow Gas	–	0.5	0.7	–	–	–	1.1
Mannville Heavy Oil	5.3	4.5	6.6	5.8	–	–	22.3
Ukalta	6.7	–	–	–	–	–	6.7
East Edson Wilrich	22.9	44.3	33.8	38.8	37.4	151.5	328.6
Total	**34.9**	**49.3**	**41.1**	**44.6**	**37.4**	**151.5**	**358.8**

(1) May not add due to rounding.

McDaniel estimates the FDC required to convert proved plus probable non-producing and undeveloped reserves to proved producing reserves, to be $358.8 million at December 31, 2019, up $12.8 million from year-end 2018. On a proved plus probable basis, FDC decreased by $0.8 million related to the future development of reserves at East Edson and increased $7.0 million in the Mannville heavy oil area and by $6.7 million in the new Ukalta area. The East Edson development plan has 66 (63.3 net) undeveloped locations (2018 – 63.3 net locations) in the total proved plus probable eight-year development plan. The Mannville Heavy Oil area has 19 (19.0 net) undeveloped locations in the total proved plus probable category, an increase of 3 from year-end 2018. The Ukalta Oil area has 5 (5.0 net) undeveloped locations in the total proved plus probable category. The projects are forecast by McDaniel to generate annual operating cash flow in excess of the annual FDC, making the projects self-funding.

RESERVE LIFE INDEX

Perpetual's proved plus probable reserves to production ratio, also referred to as reserve life index ("RLI"), was 21.5 years at year-end 2019, while the proved RLI was 13.5 years, based upon the 2020 production estimates in the McDaniel Report. The following table summarizes Perpetual's historical calculated RLI.

Reserve Life Index(1)

Year-end	2019	2018	2017	2016	2015
Total Proved	13.4	13.1	9.1	9.3	7.3
Total Proved plus Probable	21.5	19.9	13.2	15.1	11.9

(1) Calculated as year-end reserves divided by year one production estimate from the McDaniel Report.

NET PRESENT VALUE OF RESERVES SUMMARY

Perpetual's oil, natural gas and NGL reserves were evaluated by McDaniel using the Consultant Average Price Forecast effective January 1, 2020 and include the forecast impact of the Company's market diversification contract, but prior to provision for financial oil and natural gas price hedges, foreign exchange contracts, income taxes, interest, debt service charges and general and administrative expenses. The following table summarizes the NPV of future revenue from reserves at January 1, 2020, assuming various discount rates:

NPV of Reserves, before income tax(1)(2)

($ millions except as noted)	Undiscounted	5%	10%	15%	Discounted at 20%	Unit Value Discounted at 10%/Year (*$/boe*)(3)
Proved Producing	81	82	75	68	62	6.92
Proved Non-Producing	2	2	2	1	1	3.96
Proved Undeveloped	231	148	98	67	47	4.55
Total Proved	**314**	**231**	**175**	**137**	**110**	**5.32**
Probable Producing	58	39	28	21	17	8.26
Probable Non-Producing	9	6	4	3	2	3.43
Probable Undeveloped	290	156	91	57	38	4.61
Total Probable	**358**	**201**	**123**	**81**	**56**	**5.07**
Total Proved plus Probable	**671**	**432**	**297**	**217**	**167**	**5.22**

(1) January 1, 2020 Consultant Average price forecast and including market diversification contract.
(2) May not add due to rounding.
(3) The unit values are based on net reserve volumes.

McDaniel's NPV10 estimate of Perpetual's total proved plus probable reserves at year-end 2019 was $ 297 million, down 18% from $361.3 million at year-end 2018. The decrease in NPV10 reflected the impact of lower forecast commodity prices, offset by an increase in weighting to higher netback heavy oil reserves. At a 10% discount factor, total proved reserves account for 59% (2018 – 65%) of the proved plus probable value. Proved plus probable producing reserves represent 34% (2018 – 45%) of the total proved plus probable value (discounted at 10%).

FAIR MARKET VALUE OF UNDEVELOPED LAND

Perpetual's independent third-party estimate of the fair market value of its undeveloped acreage by region for purposes of the NAV calculation is based on past Crown land sale activity, adjusted for tenure and other considerations. No undeveloped land value was assigned where proved and/or probable undeveloped reserves have been booked.

Fair Market Value of Undeveloped Land

	Net Acres	Value (*$ millions*)	$/Acre
Eastern and other	101,441	6.3	62.18
West Central	19,173	15.6	815.57
Oil Sands	96,640	14.0	145.27
Total	**217,255**	**36.0**	**165.63**

The fair market value of Perpetual's undeveloped land at year-end 2019, adjusted to remove the value of undeveloped lands with reserves assigned in West Central Alberta, is estimated by an external land consultant at $36.0 million, a decrease of 9% from $39.4 million relative to year-end 2018. The fair market value of undeveloped oil sands leases incorporates the absolute investment to date in the ongoing bitumen extraction pilot project at Panny, with the remaining undeveloped land valued by historical land sale activity, adjusted for tenure.

NET ASSET VALUE

The following NAV table shows what is normally referred to as a "produce-out" NAV calculation under which the Company's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV represents the fair market value of Perpetual's shares. The calculations below do not reflect the value of the Company's prospect inventory to the extent that the prospects are not recognized within the NI 51-101 compliant reserve assessment, except as they are valued through the estimate of the fair market value of undeveloped land.

Pre-tax NAV at December 31, 2019[1]

			Discounted at	
($ millions, except as noted)	**Undiscounted**	**5%**	**10%**	**15%**
Total Proved plus Probable Reserves[2]	671.4	432.0	297.3	217.3
TOU share investment[1][3]	15.2	15.2	15.2	15.2
Fair market value of undeveloped land[4]	36.0	36.0	36.0	36.0
Bank debt, net of working capital[1]	(54.6)	(54.6)	(54.6)	(54.6)
TOU share margin loan[1][5]	(0.1)	(0.1)	(0.1)	(0.1)
Term loan[1][5]	(45.0)	(45.0)	(45.0)	(45.0)
Senior notes[1][5]	(33.6)	(33.6)	(33.6)	(33.6)
Derivatives[6]	(14.7)	(14.7)	(14.7)	(14.7)
NAV	**574.6**	**335.2**	**200.5**	**120.5**
Common shares outstanding (million)	61.31	61.31	61.31	61.31
NAV per share ($/share)	**9.37**	**5.47**	**3.27**	**1.97**

(1) Financial information is per Perpetual's 2019 audited consolidated financial statements.
(2) Reserve values per McDaniel Report as at December 31, 2019. All abandonment obligations including future abandonment and reclamation costs for pipelines and facilities and non-reserve wells are included in the McDaniel Report.
(3) Tourmaline Oil Corp. ("TOU") share value based on 1.0 million shares at the December 31, 2019 closing price ($15.22 per share).
(4) Independent third-party estimate; excludes undeveloped land in West Central Alberta with reserves assigned.
(5) Measured at principal amount.
(6) Value as at December 31, 2019, relative to the Consultant Average Price Forecast. Excludes market diversification contract which is included in total proved plus probable reserves.

The above evaluation includes FDC expectations required to bring undeveloped reserves on production, as recognized by McDaniel, that meet the criteria for booking under NI 51-101. The fair market value of undeveloped land does not reflect the value of the Company's extensive prospect inventory which is anticipated to be converted into reserves and production over time through future capital investment.

FINDING AND DEVELOPMENT COSTS

Under NI 51-101, the methodology to be used to calculate F&D costs includes incorporating changes in FDC required to bring the proved and probable undeveloped reserves to production. Changes in forecast FDC occur annually as a result of development activities, acquisitions and disposition activities, undeveloped reserve revisions and capital cost estimates that reflect the independent evaluator's best estimate of what it will cost to bring the proved plus probable undeveloped reserves on production.

2019 F&D Costs[1]

($ millions except as noted)	**Proved**	**Proved & Probable**
F&D Costs, including FDC		
Exploration and development capital expenditures[2]	$ 12.87	$ 12.87
Total change in FDC	$ (2.43)	$ 12.78
Total F&D capital, including change in FDC	$ 10.44	$ 25.65
Reserve additions, including revisions (*MMboe*)	1.11	2.43
F&D Costs, including FDC (*$/boe*)	**$ 9.37**	**$ 10.54**
FD&A Costs, including FDC		
Exploration and development capital expenditures[2]	$ 12.87	$ 12.87
Proceeds on dispositions, net of acquisitions	$ 0.00	$ 0.00
Total change in FDC	$ (2.43)	$ 12.78
Total FD&A capital, including change in FDC	$ 10.44	$ 25.65
Reserve additions, including net acquisitions (*MMboe*)	1.11	2.43
FD&A Costs, including FDC (*$/boe*)	**$ 9.37**	**$ 10.54**

(1) Financial information is per Perpetual's 2019 audited consolidated financial statements.
(2) Excludes corporate assets and expenditures on decommissioning obligations.

2020 OUTLOOK

The Company's Board of Directors approved a capital spending program of $6 million for the first quarter of 2020 to drill four (4.0 net) multi-lateral horizontal wells at Ukalta. Perpetual's reserve-based credit facility is currently undergoing its borrowing limit redetermination which is likely to reduce the current $45 million borrowing limit effective March 31, 2020 due to reductions in bank lending commodity price forecasts. Any reductions in the credit facility borrowing limit will reduce the Company's available liquidity. To preserve liquidity, the Company will defer further capital spending until the credit facility borrowing limit redetermination has been completed. The Company will issue its 2020 Guidance once the borrowing limit redetermination is known and capital spending plans have been determined.

FINANCIAL AND OPERATING HIGHLIGHTS

($Cdn thousands, except volume and per share amounts)	Three Months ended December 31 2019	2018[4]	Change	Year ended December 31 2019	2018[4]	Change
Financial						
Oil and natural gas revenue	**15,830**	21,510	(26%)	**74,361**	86,128	(14%)
Net loss	**(32,498)**	(331)	(9,718%)	**(94,015)**	(20,380)	(361%)
Per share – basic and diluted[2]	**(0.54)**	(0.01)	(5,300%)	**(1.56)**	(0.34)	(359%)
Cash flow from (used in) operating activities	**(1,290)**	5,163	(125%)	**17,806**	31,525	(44%)
Per share[1][2]	**(0.02)**	0.09	(122%)	**0.30**	0.53	(43%)
Adjusted funds flow[1]	**340**	8,052	(96%)	**14,534**	30,155	(52%)
Per share[2]	**0.01**	0.13	(92%)	**0.24**	0.50	(52%)
Revolving bank debt	**47,552**	42,561	12%	**47,552**	42,561	12%
Senior notes, principal amount	**33,580**	32,490	3%	**33,580**	32,490	3%
Term loan, principal amount	**45,000**	45,000	–	**45,000**	45,000	–
TOU share margin demand loan, principal amount	**100**	14,144	(99%)	**100**	14,144	(99%)
TOU share investment	**(15,220)**	(28,132)	(46%)	**(15,220)**	(28,132)	(46%)
Net working capital deficiency[1]	**7,068**	6,543	8%	**7,068**	6,543	8%
Total net debt[1]	**118,080**	112,606	5%	**118,080**	112,606	5%
Net capital expenditures						
Capital expenditures	**1,995**	5,617	(64%)	**12,939**	26,888	(52%)
Net proceeds from dispositions	**–**	(1,285)	(100%)	**–**	(3,030)	(100%)
Net capital expenditures	**1,995**	4,332	(54%)	**12,939**	23,858	(46%)
Common shares outstanding *(thousands)*						
End of period[3]	**60,513**	60,240	**–**	**60,513**	60,240	**–**
Weighted average – basic and diluted	**60,444**	60,448	**–**	**60,258**	60,039	**–**
Operating						
Average production						
Natural gas *(MMcf/d)*	**36.6**	44.9	(18%)	**42.3**	52.6	(20%)
Oil *(bbl/d)*	**1,275**	1,301	(2%)	**1,224**	1,050	17%
NGL *(bbl/d)*	**606**	715	(15%)	**719**	774	(7%)
Total *(boe/d)*	**7,991**	9,491	(16%)	**8,988**	10,594	(15%)
Average prices						
Realized natural gas price *($/Mcf)*	**2.00**	4.38	(54%)	**2.77**	3.05	(9%)
Realized oil price *($/bbl)*	**43.85**	19.83	121%	**44.87**	40.62	10%
Realized NGL price *($/bbl)*	**43.93**	35.73	23%	**41.01**	52.96	(23%)
Wells drilled						
Natural gas – gross (net)	**– (–)**	– (–)		**– (–)**	1 (1.0)	
Oil – gross (net)	**– (–)**	– (–)		**5 (5.0)**	6 (6.0)	
Total – gross (net)	**– (–)**	– (–)		**5 (5.0)**	7 (7.0)	

(1) These are non-GAAP measures. Please refer to "Non-GAAP Measures" at the end of the MD&A.
(2) Based on weighted average basic common shares outstanding for the period.
(3) All common shares are net of shares held in trust (2019 – 801; 2018 – 661). See "Note 17 to the Audited Consolidated Financial Statements".
(4) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in the MD&A.

ADVISORIES

The letter to shareholders and 2019 annual highlights refer to certain non-GAAP measures and metrics commonly used in the oil and natural gas industry and provides forward-looking information and statements. Further detailed information regarding these measures is provided in "*Management's Discussion and Analysis – Advisories*" on pages 12 and 13, "*Management's Discussion and Analysis – Critical Accounting Estimates – Forward-Looking Information and Statements*" on pages 34 and 35 and "*Management's Discussion and Analysis – Risk Factors – Oil and Gas Advisories*" on page 36 of these annual results.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Perpetual Energy Inc.'s ("Perpetual", the "Company" or the "Corporation") operating and financial results for the year ended December 31, 2019 as well as information and estimates concerning the Corporation's future outlook based on currently available information. This discussion should be read in conjunction with the Corporation's audited consolidated financial statements and accompanying notes for the years ended December 31, 2019 and 2018. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). The Corporation adopted IFRS 16, "Leases" ("IFRS 16"), effective January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section of this MD&A for further information. Readers are referred to the advisories for additional information regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information and Statements" section of this MD&A. The date of this MD&A is March 18, 2020.

NATURE OF BUSINESS: Perpetual is an oil and natural gas exploration, production and marketing company headquartered in Calgary, Alberta. Perpetual operates a diversified asset portfolio, including liquids-rich natural gas assets in the deep basin of West Central Alberta, heavy oil and shallow natural gas in Eastern Alberta, and undeveloped oil sands leases in Northern Alberta. Additional information on Perpetual, including the most recently filed Annual Information Form ("AIF"), can be accessed at www.sedar.com or from the Corporation's website at www.perpetualenergyinc.com.

ADVISORIES

NON-GAAP MEASURES: The terms "adjusted funds flow", "adjusted funds flow per share", "adjusted funds flow per boe", "available liquidity", "cash costs", "gas over bitumen revenue, net of payments", "net working capital deficiency (surplus)", "net debt", "net bank debt", "net debt to adjusted funds flow ratio", "operating netback", "realized revenue", and "enterprise value" used in this MD&A are not recognized under GAAP. Management believes that in addition to net income (loss) and net cash flows from (used in) operating activities as defined by GAAP, these terms are useful supplemental measures to evaluate performance. Users are cautioned however that these measures should not be construed as an alternative to net income (loss) or net cash flows from (used in) operating activities determined in accordance with GAAP as an indication of Perpetual's performance, and may not be comparable with the calculation of similar measurements by other entities.

Adjusted funds flow: Management uses adjusted funds flow and adjusted funds flow per boe as key measures to assess the ability of the Company to generate the funds necessary to finance capital expenditures, expenditures on decommissioning obligations and meet its financial obligations. Adjusted funds flow is calculated based on cash flows from (used in) operating activities, excluding changes in non-cash working capital and expenditures on decommissioning obligations since Perpetual believes the timing of collection, payment or incurrence of these items is variable. Expenditures on decommissioning obligations may vary from period to period depending on capital programs and the maturity of the Company's operating areas. Expenditures on decommissioning obligations are managed through the capital budgeting process which considers available adjusted funds flow. The Company has also deducted payments of the gas over bitumen royalty financing from adjusted funds flow 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 employee downsizing costs, which management considers to not be related to cash flow from operating activities.

Adjusted funds flow per share is calculated using the same weighted average number of shares outstanding used in calculating net 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 December 31,		Years ended December 31,	
(*$ thousands, except per share and per boe amounts*)	**2019**	2018	**2019**	2018
Net cash flows from (used in) operating activities	**(1,290)**	5,163	**17,806**	31,525
Change in non-cash working capital	**705**	2,284	**(4,602)**	(2,541)
Decommissioning obligations settled	**540**	811	**1,733**	1,969
Payments of gas over bitumen royalty financing	**(225)**	(257)	**(1,013)**	(1,135)
Payments of restructuring costs	**610**	51	**610**	337
Adjusted funds flow	**340**	8,052	**14,534**	30,155
Adjusted funds flow per share	**0.01**	0.13	**0.24**	0.50
Adjusted funds flow per boe	**0.46**	9.22	**4.43**	7.80

(1) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach, resulting in an increase in net cash flows from operating activities and adjusted funds flow of $0.2 million for the year ended December 31, 2019. Comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

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

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

($ thousands, except per boe amounts)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
Royalties	**3,383**	2,283	**11,260**	10,594
Production and operating	**3,839**	4,851	**18,332**	19,229
Transportation	**1,551**	1,489	**6,258**	6,068
General and administrative	**2,406**	3,793	**11,660**	13,630
Cash finance expense	**2,376**	2,242	**9,280**	8,707
Cash costs	**13,555**	14,658	**56,790**	58,228
Cash costs per boe	**18.44**	16.79	**17.31**	15.06

Realized revenue: Realized revenue is the sum of realized natural gas revenue, realized oil revenue and realized natural gas liquids ("NGL") revenue which includes realized gains (losses) on financial natural gas, crude oil, NGL and foreign exchange contracts but excludes any realized losses resulting from marketing contracts associated with the disposition of the shallow gas assets on October 1, 2016 (the "Shallow Gas Disposition") to Sequoia Resources Corp. ("Sequoia"). Realized revenue, including foreign exchange and the market diversification contract, is used by management to calculate the Corporation's net realized commodity prices, taking into account monthly settlements of financial crude oil and natural gas forward sales, collars, basis differentials, and forward foreign exchange sales. These contracts are put in place to protect Perpetual's adjusted funds flow from potential volatility in commodity prices and foreign exchange rates. Any related realized gains or losses are considered part of the Corporation's realized commodity price.

Gas over bitumen revenue, net of payments: Gas over bitumen revenue, net of payments, includes gas over bitumen royalty credits less monthly payments of the gas over bitumen royalty financing. This is used by management to calculate the Corporation's net realized gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty credits.

Operating netback: Operating netback is calculated by deducting royalties, production and operating expenses, 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. Perpetual considers operating netback to be an important performance measure as it demonstrates its profitability relative to current commodity prices.

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, TOU share investment, TOU share margin demand loan, revolving bank debt, current portion of gas over bitumen royalty financing, current portion of lease liabilities, and current portion of provisions.

Net bank debt, net debt, and net debt to adjusted funds flow ratio: Net bank debt is measured as current and long-term revolving bank debt including net working capital deficiency (surplus). Net debt includes the carrying value of net bank debt, the principal amount of the term loan, the principal amount of the TOU share margin demand loan and the principal amount of senior notes, reduced for the fair value of the TOU share investment. Net debt, net bank debt, and net debt to adjusted funds flow ratios are used by management to assess the Corporation's overall debt position and borrowing capacity. Net debt to adjusted funds flow ratios are calculated on a trailing twelve-month basis.

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

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

FOURTH QUARTER 2019 HIGHLIGHTS

Fourth quarter exploration and development expenditures of $2.0 million were directed towards the Eastern Alberta core area, and included initial costs to drill two (2.0 net) heavy oil wells targeting the Clearwater formation at Ukalta that were spud in late December. These two wells were brought on production in late January, with an additional two (2.0 net) wells drilled, completed, and put on production in late-February. Exploration and development expenditures also included funds to acquire additional undeveloped crown lands focused on the Clearwater play in its Eastern Alberta core area.

Production averaged 7,991 boe/d in the fourth quarter, down 16% from the prior year period due to lower natural gas and NGL production which resulted from the deferral of gas-focused capital spending in response to continued low natural gas prices. Compared to the prior year period, production was also impacted by the shut-in of 1.8 MMcf/d (300 boe/d) of production at the Company's Panny property in Eastern Alberta in the third quarter of 2019. Perpetual expects this production to remain offline indefinitely, or until excessive property tax assessments are reduced.

Realized revenue was $14.3 million in the fourth quarter, down 37% from the prior year period, due to a 16% decrease in production combined with a 25% decrease in realized revenue per boe related to lower NYMEX natural gas prices and hedging losses. Decreased realized pricing in the fourth quarter of 2019 reflected realized losses on derivatives of $1.5 million, compared to realized gains of $1.3 million in the prior year period. In addition, the market diversification contract eroded natural gas revenue by $0.2 million during the fourth quarter due to the relative increase in AECO Daily Index Prices compared to NYMEX. AECO prices strengthened during the fourth quarter in response to changes made to TC Energy's NGTL natural gas pipeline maintenance operating protocols that were implemented in early October. In anticipation of tightening basis differentials, Perpetual modified its 40,000 MMBtu/d market diversification contract in late September to shift its pricing back to AECO for the December 2019 to October 2020 period. Realized heavy oil and NGL prices improved significantly over the prior year, increasing 121% and 23% respectively from fourth quarter 2018 prices. The increase in realized oil prices was due to the substantial narrowing of the WCS differential to US$15.83/bbl from US$39.42/bbl in the fourth quarter of 2018, which far outweighed the 3% decrease in WTI benchmark pricing over the same period.

Cash costs were $13.6 million in the fourth quarter, a decrease of $1.1 million (8%) from the prior year period due primarily to a $1.4 million reduction in general and administrative costs compared to the prior year period, resulting from the reduction of approximately 25% of Perpetual's corporate employee head count, combined with a reduction in compensation for remaining employees that was implemented at the end of the third quarter.

The net loss for the fourth quarter of 2019 was $32.5 million ($0.54/share) compared to $0.3 million ($0.01/share) in the prior year period. The increase in net loss was due primarily to impairment charges of $24.5 million recognized during the fourth quarter of 2019, combined with unrealized losses on derivatives of $3.4 million (Q4 2018 – unrealized gains of $10.9 million) associated with the tightening of the basis differential between NYMEX natural gas futures prices and AECO futures prices in the fourth quarter, partially offset by an unrealized gain on the Tourmaline Oil Corp. ("TOU") share investment of $3.2 million (Q4 2018 – unrealized loss of $9.5 million).

Net cash flows used in operating activities were $1.3 million, compared to $5.2 million of cash flows from operating activities in the prior year period. The decrease was due to the 16% decrease in production combined with realized natural gas prices which were 54% lower than the prior year.

Adjusted funds flow for the fourth quarter of 2019 was $0.3 million ($0.01/share), down 96% from $8.1 million ($0.13/share) in the prior year period, due to the decrease in production combined with significantly lower realized natural gas prices caused by the change in basis differentials between NYMEX and AECO based markets.

In December 2019, Perpetual sold 656,773 TOU shares at a weighted average price of $14.78 per share and used the proceeds of $9.7 million to partially repay the TOU share margin demand loan. In January 2020, the Company sold its remaining 1,000,000 TOU shares for net cash proceeds of $14.3 million. Net proceeds were used to fully repay the TOU share margin demand loan and to repay a portion of the Credit Facility.

2019 ANNUAL HIGHLIGHTS

Perpetual's 2019 capital program was funded from adjusted funds flow, with investment weighted to heavy oil drilling in Eastern Alberta. Exploration and development capital spending of $12.9 million (2018 – $26.5 million), resulted in finding and development costs ("F&D") of $10.54/boe (2018 – $5.09/boe) on a proved and probable basis, including changes in future development capital ("FDC"). Combined with an operating netback of $11.50/boe (2018 – $13.79/boe), Perpetual achieved an F&D recycle ratio of 1.1 times (2018 F&D recycle ratio – 2.7 times). The Company added proved plus probable reserves of 2.4 million boe to replace 74% of 2019 production. In 2018, the Company added proved plus probable reserves of 5.2 million boe to replace 134% of 2018 production.

Production in 2019 averaged 8,988 boe/d (22% oil and NGL), a decrease of 15% from 10,594 boe/d (17% oil and NGL) in 2018. Production peaked during the first quarter of 2019 and then declined for the remainder of the year, as drilling activity at East Edson was deferred pending higher natural gas prices. The Company drilled five (5.0 net) wells targeting heavy oil in Eastern Alberta, including two (2.0 net) horizontal multi-lateral wells to delineate new reserves in the Clearwater formation at Ukalta. These wells, combined with the four (4.0 net) new first quarter 2020 horizontal multi-lateral drills, are producing heavy oil at a combined rate of 730 bbl/d from Ukalta.

Realized revenue was $73.6 million in 2019, down 18% from $89.2 million in 2018 due primarily to the 15% decrease in annual production. Realized revenue was also negatively impacted by realized losses on derivatives of $0.8 million (2018 – realized gains of $3.1 million). Market diversification contract natural gas sales contributed an incremental $0.64/Mcf over the AECO Daily Index average price in 2019 (2018 – $1.02/Mcf).

Cash costs were $56.8 million in 2019, down $1.4 million (2%) from 2018 cash costs due primarily to the reduction in general and administrative costs implemented at the end of the third quarter. Production and operating expenses also decreased by 5% over the prior year, due to the absence of $1.0 million in remediation and water hauling costs from the Mannville produced water spill which occurred in the third quarter of 2018.

The net loss for 2019 was $94.0 million ($1.56/share), up from $20.4 million in 2018 ($0.34/share). The net loss was negatively impacted by the $21.9 million unrealized loss on derivatives (2018 – unrealized gain of $5.7 million) in addition to impairment losses of $47.1 million which were recognized in 2019 (2018 - $7.2 million), reflecting the decrease in forward natural gas and NGL pricing during 2019. An unrealized loss of $3.2 million recognized in 2019 related to the change in fair value of the TOU share investment (2018 – $9.6 million) also contributed to the net loss.

For the year ended December 31, 2019, net cash flow from operating activities was $17.8 million compared to $31.5 million in 2018. The decrease was driven by the 15% decrease in production and lower realized natural gas prices, despite the increased weighting of higher value oil and NGL in the production mix. Realized revenue of $22.43/boe was only 3% lower than the prior year (2018 – $23.07/boe). The increase in unrealized losses on derivatives and impairment losses in 2019 did not impact cash flow from operating activities.

For the year ended December 31, 2019, adjusted funds flow was $14.5 million ($0.24/share), down $15.6 million (52%) from $30.2 million ($0.50/share) in 2018 as the impact of the 15% year-over-year decrease in production combined with lower natural gas and NGL prices outweighed the 2% decrease in cash costs and increased heavy oil production.

SEQUOIA LITIGATION UPDATE

On August 15, 2019, the Court of Queen's Bench (the "Court") delivered the oral decision related to the Statement of Claim filed against Perpetual and its President and Chief Executive Officer ("CEO") on August 3, 2018, and on January 13, 2020, the Court issued its written decision with respect to the Company's disposition of shallow gas assets in Eastern Alberta to an unrelated third party on October 1, 2016 (the "Sequoia Litigation"). The decision dismissed and struck all but one of the claims filed by PwC in its capacity as trustee (the "Trustee") in bankruptcy of Sequoia Resources Corp ("Sequoia"). The Court did not find that the test for summary dismissal relating to whether the transaction was an arm's length transfer for purposes of section 96(1) of the Bankruptcy and Insolvency Act (the "BIA") was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim can continue against Perpetual. On August 23, 2019, the Trustee filed a notice of appeal with the Court of Appeal of Alberta, contesting the entire August 15, 2019 oral decision, and on August 26, 2019, Perpetual and its CEO filed a similar notice of appeal contesting the BIA claim portion of the oral decision. The appeal proceedings are scheduled to be heard in December 2020.

On September 24, 2019, Perpetual filed an application for security for costs of the appeal. On January 28, 2020, the Court of Appeal issued its decision with respect to Perpetual's security for costs application, requiring the Trustee to post security with the Court of Appeal in the amount of $0.2 million prior to proceeding with its appeal. Applications have been filed by the Trustee to appeal the security for costs decision and alter the reasons for the decision. The Court of Appeal is scheduled to hear these applications in June 2020.

On February 25, 2020, Perpetual filed a new application to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the transaction nor caused to be insolvent by the transaction. The Court is scheduled to hear this application in June 2020.

Management expects that the Company is more likely than not to be successful in defending against the Sequoia litigation such that no damages will be awarded against it, and therefore, no amounts have been accrued as a liability in Perpetual's financial statements.

FUTURE OPERATIONS

Perpetual has a first lien, reserve-based credit facility (the "Credit Facility"). On December 24, 2019, Perpetual's syndicate of lenders completed their semi-annual borrowing base redetermination, reducing the Credit Facility borrowing limit (the "Borrowing Limit") from $55 million to $45 million effective January 22, 2020. In January 2020, the Company sold its remaining 1,000,000 TOU shares for net cash proceeds of $14.3 million (the "TOU Share Proceeds"). Net proceeds were used to repay the TOU share margin demand loan with the balance used to repay a portion of the Credit Facility. The next Borrowing Limit redetermination is scheduled on or prior to March 31, 2020. If the Credit Facility repayment term is not extended at the next redetermination, all outstanding advances will become payable on November 30, 2020. The extension of the Credit Facility repayment term is dependent on the Company's ability to repay or extend the term of the $45 million second lien term loan that matures and requires repayment on March 14, 2021. The Company also has $33.6 million of unsecured senior notes that mature on January 23, 2022.

Perpetual had available liquidity at December 31, 2019 of $20.2 million, comprised of $5.1 million of available borrowings under the Credit Facility and the $15.2 million TOU share investment market value net of the associated $0.1 million TOU share margin demand loan. After giving pro forma effect to $45 million Borrowing Limit effective on January 22, 2020, and the TOU Share Proceeds, Perpetual had available liquidity at December 31, 2019 of $9.2 million.

Although the TOU Share Proceeds have reduced the Company's revolving bank debt borrowed under its Credit Facility, the Company remains dependent on the support of its lenders to the Credit Facility which has a current maturity of November 30, 2020. Further, the recent significant decline in natural gas and liquids prices has contributed to the Company projecting a significant reduction in cash flow from operating activities in 2020. The Company will require additional financing or will need to refinance the upcoming Credit Facility and term loan maturities as the available liquidity and operating cash flows are not anticipated to be sufficient. Perpetual is considering options including the sale or monetization of additional assets, the extension of existing debt maturity dates, or alternative financing.

However, due to the facts and circumstances detailed above coupled with considerable economic instability and uncertainty in the oil and gas markets which negatively impacts operating cash flows and lender and investor sentiment, there remains considerable risk around the Company's ability to address its liquidity shortfalls and upcoming maturities. In addition, there continues to be some uncertainty regarding the Statement of Claim which may restrict management's ability to manage its capital structure. As a result, there is a material uncertainty surrounding the Company's ability to continue as a going concern that creates significant doubt as to the ability of the Company to meets its obligations as they come due and, therefore, it may be unable to realize its assets and discharge its liabilities in the normal course of business.

These financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Corporation will be able to realize its assets and discharge its liabilities in the normal course of business. These financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern basis were not appropriate for these financial statements, then adjustments would be necessary in the carrying value of the assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

2020 GUIDANCE

The Company's Board of Directors approved a capital spending program of $6 million for the first quarter of 2020 to drill four (4.0 net) multi-lateral horizontal wells at Ukalta. Perpetual's reserve-based credit facility is currently undergoing its borrowing limit redetermination which is likely to reduce the current $45 million borrowing limit effective March 31, 2020 due to reductions in bank lending commodity price forecasts. Any reductions in the credit facility borrowing limit will reduce the Company's available liquidity. To preserve liquidity, the Company will defer further capital spending until the credit facility borrowing limit redetermination has been completed. The Company will issue its 2020 Guidance once the borrowing limit redetermination is known and capital spending plans have been determined.

2019 FOURTH QUARTER AND ANNUAL CAPITAL EXPENDITURES

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2019**	2018	**2019**	2018
Exploration and development	**1,983**	5,613	**12,865**	26,535
Corporate assets	**12**	4	**74**	353
Capital expenditures	**1,995**	5,617	**12,939**	26,888
Acquisitions	**–**	–	**–**	1,871
Proceeds from dispositions of oil and gas properties	**–**	(1,285)	**–**	(13,441)
Net capital expenditures	**1,995**	4,332	**12,939**	15,318

Exploration and development spending by area

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2019**	2018	**2019**	2018
West Central	**12**	4,235	**1,185**	13,665
Eastern	**1,971**	1,378	**11,680**	12,870
Total	**1,983**	5,613	**12,865**	26,535

Wells drilled by area

	Three months ended December 31,		Years ended December 31,	
(gross/net)	**2019**	2018	**2019**	2018
West Central	**–/–**	–/–	**–/–**	1/1.0
Eastern Alberta	**–/–**	–/–	**5/5.0(1)**	6/6.0
Total	**–/–**	–/–	**5/5.0(1)**	7/7.0

(1) Excludes the re-entry of one existing well bore at Mannville.

Perpetual's exploration and development spending in the fourth quarter of 2019 was $2.0 million, 18% higher than capital spending guidance provided with Perpetual's third quarter earnings release. Fourth quarter spending was focused in Eastern Alberta and included costs to acquire additional undeveloped crown lands focused on the Clearwater play, as well as initial costs to spud two (2.0 net) heavy oil wells targeting the Clearwater formation at Ukalta in late December. These two new wells were brought on production in late January. Two (2.0 net) additional step out wells at Ukalta were drilled and completed in the first quarter of 2020, and put on production in late-February. These four wells are currently producing at a combined rate of 540 bbl/d.

For the year ended December 31, 2019, exploration and development spending was $12.9 million, down 52% from 2018 as the 2019 program was purposefully managed to be funded from adjusted funds flow. The Company added proved plus probable reserves at an F&D cost, including changes in FDC of $10.54/boe. In addition, the Company added proved plus probable reserves of 2.4 million boe in 2019 to replace 74% of production. The Company added proved reserves at a F&D cost, including changes in FDC of $9.38/boe.

Spending in Eastern Alberta in 2019 was $11.7 million. At Mannville, three (3.0 net) horizontal wells were drilled in the second quarter of 2019, along with a re-entry to add two additional laterals to an existing oil well. At Ukalta, two (2.0 net) initial exploratory wells were drilled, completed and tied-in during the third quarter. The four (4.0 net) well winter drilling program was initiated late in the fourth quarter.

Spending in West Central in 2019 was $1.2 million, and was primarily directed towards the installation of field compression equipment and a sweetening tower to restore higher liquids ratio natural gas wells back to production.

Acquisitions and Dispositions

Proceeds (payments) on dispositions

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2019**	2018	**2019**	2018
Proceeds from dispositions of oil and gas properties	**–**	1,285	**–**	13,441
Payments on retained shallow gas marketing arrangements(1)	**–**	–	**–**	(8,540)
Net proceeds on dispositions	**–**	1,285	**–**	4,901

Gain (loss) on dispositions

	Three months ended December 31,		Years ended December 31,	
(*$ thousands*)	**2019**	2018	**2019**	2018
Proceeds on dispositions of oil and gas properties	**–**	1,285	**–**	13,441
Carrying amount of PP&E disposed	**–**	–	**–**	(848)
Carrying amount of E&E disposed	**–**	(1,495)	**–**	(12,442)
Carrying amount of ARO disposed	**–**	120	**–**	500
Gain (loss) on disposition of oil and gas properties	**–**	(90)	**–**	651
Realized loss on retained shallow gas marketing arrangements(1)	**–**	–	**–**	(874)
Loss on dispositions	**–**	(90)	**–**	(223)

(1) Related to the Shallow Gas Disposition to Sequoia.

The Company did not complete any acquisitions or dispositions during the three months or year ended December 31, 2019. Net proceeds on dispositions were $1.3 million in the fourth quarter of 2018 and included the sale of the Company's Waskahigan area interests to a third party for cash consideration and a retained 1% gross overriding royalty on undeveloped lands to maintain exposure to future drilling conducted by the purchaser. For the year ended December 31, 2018, dispositions included the sale of non-core royalty interests and exploration and evaluation oil and gas properties for gross proceeds of $13.4 million and the transfer to the purchaser of $0.5 million in associated decommissioning obligations, resulting in a net gain of $0.7 million.

Expenditures on decommissioning obligations

During the three months ended December 31, 2019, Perpetual spent $0.5 million (Q4 2018 – $0.8 million) on abandonment and reclamation projects, consistent with previous guidance provided with Perpetual's third quarter earnings release. As part of Perpetual's focus on well and pipeline abandonment and reclamation, four reclamation certificates were received from the Alberta Energy Regulator ("AER") during the fourth quarter of 2019 (Q4 2018 – three reclamation certificates) which will result in the cessation of associated property tax and surface lease expenses. For the year ended December 31, 2019, Perpetual spent $1.7 million (2018 – $2.0 million) on abandonment and reclamation projects under the AER's area-based closure approach and has received 20 reclamation certificates to date (2018 – 18 reclamation certificates). Abandonment and reclamation expenditures of $1.5 million are forecast in 2020, focused in Mannville utilizing the area-based closure approach.

SUMMARY OF QUARTERLY AND ANNUAL NET LOSS

Three months ended December 31,

		2019		2018
	($ thousands)	***($/boe)***	*($ thousands)*	*($/boe)*
Realized revenue[(1)]	**14,335**	**19.50**	22,797	26.11
Royalties	**(3,383)**	**(4.60)**	(2,283)	(2.61)
Production and operating expenses	**(3,839)**	**(5.22)**	(4,851)	(5.56)
Transportation costs	**(1,551)**	**(2.11)**	(1,489)	(1.71)
Operating netback[(1)]	**5,562**	**7.57**	14,174	16.23
Unrealized change in fair value of derivatives	**(3,369)**	**(4.58)**	10,885	12.47
Gas over bitumen royalty credit	**202**	**0.27**	302	0.35
Exploration and evaluation	**(811)**	**(1.10)**	(1,617)	(1.85)
General and administrative	**(2,406)**	**(3.27)**	(3,793)	(4.34)
Share-based payments	**(488)**	**(0.66)**	(566)	(0.65)
Depletion and depreciation	**(6,960)**	**(9.47)**	(7,777)	(8.91)
Loss on dispositions	**–**	**–**	(90)	(0.10)
Impairment	**(24,452)**	**(33.26)**	–	–
Finance expense	**(2,981)**	**(4.05)**	(2,306)	(2.64)
Change in fair value of TOU share investment	**3,205**	**4.36**	(9,543)	(10.93)
Net loss	**(32,498)**	**(44.19)**	(331)	(0.38)
Net loss per share - basic	**(0.54)**		(0.01)	

Years ended December 31,

		2019		2018
	($ thousands)	***($/boe)***	*($ thousands)*	*($/boe)*
Realized revenue[(1)]	**73,572**	**22.43**	89,199	23.07
Royalties	**(11,260)**	**(3.43)**	(10,594)	(2.74)
Production and operating expenses	**(18,332)**	**(5.59)**	(19,229)	(4.97)
Transportation costs	**(6,258)**	**(1.91)**	(6,068)	(1.57)
Operating netback[(1)]	**37,722**	**11.50**	53,308	13.79
Unrealized change in fair value of derivatives	**(21,893)**	**(6.67)**	5,747	1.49
Gas over bitumen royalty credit	**852**	**0.26**	1,046	0.27
Exploration and evaluation	**(1,797)**	**(0.55)**	(2,212)	(0.57)
General and administrative	**(11,660)**	**(3.55)**	(13,630)	(3.52)
Share-based payments	**(2,295)**	**(0.70)**	(2,573)	(0.67)
Depletion and depreciation	**(31,188)**	**(9.51)**	(34,946)	(9.04)
Loss on dispositions	**–**	**–**	(223)	(0.06)
Impairment	**(47,052)**	**(14.34)**	(7,200)	(1.86)
Finance expense	**(11,951)**	**(3.64)**	(10,122)	(2.62)
Change in fair value of TOU share investment	**(3,207)**	**(0.98)**	(9,575)	(2.48)
Restructuring costs	**(1,546)**	**(0.47)**	–	–
Net loss	**(94,015)**	**(28.65)**	(20,380)	(5.27)
Net loss per share - basic	**(1.56)**		(0.34)	

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

Operating Netbacks

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

	Three months ended December 31, 2019			Three months ended December 31, 2018		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Petroleum and natural gas ("P&NG") revenue(1)	**9,366**	**6,464**	**15,830**	17,481	4,029	21,510
Realized gains (losses) on derivatives(2)	**–**	**–**	**(1,495)**	–	–	1,287
Royalties	**(2,584)**	**(799)**	**(3,383)**	(1,611)	(672)	(2,283)
Production and operating expenses(3)	**(1,698)**	**(2,141)**	**(3,839)**	(1,598)	(3,253)	(4,851)
Transportation costs	**(944)**	**(607)**	**(1,551)**	(1,085)	(404)	(1,489)
Operating netback	**4,140**	**2,917**	**5,562**	13,187	(300)	14,174

	Year ended December 31, 2019			Year ended December 31, 2018		
($ thousands)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Petroleum and natural gas revenue(1)	**47,199**	**27,162**	**74,361**	65,383	20,745	86,128
Realized gains (losses) on derivatives(2)	**–**	**–**	**(789)**	–	–	3,071
Royalties	**(7,833)**	**(3,427)**	**(11,260)**	(8,156)	(2,438)	(10,594)
Production and operating expenses(3)	**(7,188)**	**(11,144)**	**(18,332)**	(7,160)	(12,069)	(19,229)
Transportation costs	**(4,176)**	**(2,082)**	**(6,258)**	(4,616)	(1,452)	(6,068)
Operating netback	**28,002**	**10,509**	**37,722**	45,451	4,786	53,308

	Three months ended December 31, 2019			Three months ended December 31, 2018		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**6,253**	**1,738**	**7,991**	7,460	2,031	9,491
Petroleum and natural gas revenue(1)	**16.28**	**40.43**	**21.53**	25.47	21.56	24.63
Realized gains (losses) on derivatives(2)	**–**	**–**	**(2.03)**	–	–	1.48
Royalties	**(4.49)**	**(5.00)**	**(4.60)**	(2.35)	(3.60)	(2.61)
Production and operating expenses(3)	**(2.95)**	**(13.39)**	**(5.22)**	(2.33)	(17.40)	(5.56)
Transportation costs	**(1.64)**	**(3.80)**	**(2.11)**	(1.58)	(2.16)	(1.71)
Operating netback	**7.20**	**18.24**	**7.57**	19.21	(1.60)	16.23

	Year ended December 31, 2019			Year ended December 31, 2018		
($/boe)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**7,176**	**1,812**	**8,988**	8,737	1,857	10,594
Petroleum and natural gas revenue(1)	**18.02**	**41.06**	**22.67**	20.50	30.61	22.27
Realized gains (losses) on derivatives(2)	**–**	**–**	**(0.24)**	–	–	0.80
Royalties	**(2.99)**	**(5.18)**	**(3.43)**	(2.56)	(3.60)	(2.74)
Production and operating expenses(3)	**(2.74)**	**(16.84)**	**(5.59)**	(2.25)	(17.81)	(4.97)
Transportation costs	**(1.59)**	**(3.15)**	**(1.91)**	(1.45)	(2.14)	(1.57)
Operating netback	**10.70**	**15.89**	**11.50**	14.24	7.06	13.79

(1) Includes revenues related to the natural gas market diversification contract and physical forward sales contracts which settled during the period.
(2) Includes realized gains on financial derivatives and financial prompt month price optimization contracts. Realized gains and losses on financial derivatives are not allocated to the Company's core areas. Includes proceeds of $2.7 million ($0.17/Mcf) for the year ended December 31, 2019 received from the monetization of the Company's market diversification contract for the December 2019 to October 2020 period.
(3) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

For the fourth quarter of 2019, Perpetual's operating netback of $5.6 million ($7.57/boe) decreased 61% from $14.2 million ($16.23/boe) in the prior year period due to a 16% decrease in production combined with a 25% decrease in realized revenue per boe. Lower production was the result of natural declines at West Central, where capital expenditures were minimal in 2019 as a result of low natural gas prices. Lower realized revenue per boe was due to a 54% reduction in realized natural gas prices, reflecting weaker NYMEX natural gas prices compared to the fourth quarter of 2018, partially offset by higher realized oil and NGL prices. Canadian oil price differentials improved significantly in 2019 due to the implementation of production curtailments by the Government of Alberta. Perpetual's oil production is not subject to curtailment as its total production is below the designated curtailment production level.

For the year ended December 31, 2019, Perpetual's operating netback of $37.7 million ($11.50/boe) decreased 29% from $53.3 million ($13.79/boe) in 2018. The decrease in the 2019 operating netback was due to a 15% decline in production combined with the 17% decrease in operating netback per boe, which was the result of lower realized natural gas and NGL prices of 9% and 23% respectively and higher costs per boe.

Production

	Three months ended December 31,		Years ended December 31,	
	2019	2018	**2019**	2018
Natural gas (*MMcf/d*)				
Eastern Alberta	**2.8**	4.6	**3.6**	5.1
West Central	**33.8**	40.3	**38.7**	47.5
Total natural gas(1)	**36.6**	44.9	**42.3**	52.6
Crude oil (*bbl/d*)				
Eastern Alberta(2)	**1,264**	1,265	**1,216**	1,020
West Central	**11**	36	**8**	30
Total crude oil	**1,275**	1,301	**1,224**	1,050
Total NGL (*bbl/d*)(3)	**606**	715	**719**	774
Total production (*boe/d*)	**7,991**	9,491	**8,988**	10,594

(1) Natural gas production yields a heat content of 1.17 GJ/Mcf, resulting in higher realized natural gas prices on a $/Mcf basis. See "Commodity Prices".
(2) Primarily heavy oil.
(3) Primarily West Central liquids-rich gas.

Fourth quarter production averaged 7,991 boe/d (24% oil and NGL), down 1,500 boe/d or 16% from 9,491 boe/d in the prior year period (21% oil and NGL). Fourth quarter production was reduced by natural declines at East Edson in addition to the shut-in of 1.8 MMcf/d (300 boe/d) of production at the Company's Panny property in Eastern Alberta. This production was shut-in during the third quarter and Perpetual expects it to remain offline indefinitely, or until excessive property tax assessments are reduced. Fourth quarter production was at the low end of guidance provided with Perpetual's third quarter earnings release due to higher well maintenance downtime at the Mannville heavy oil operations.

Fourth quarter natural gas production averaged 33.8 MMcf/d at West Central, a decrease of 16% from the comparative period of 2018. The decrease was driven by natural declines resulting from limited capital investment during 2019 in response to low AECO natural gas prices.

West Central NGL yields were consistent with the fourth quarter of 2018 and previous quarters in 2019 at approximately 18 bbls per MMcf of natural gas produced.

Crude oil production in Eastern Alberta was consistent with the fourth quarter of 2018 at 1,264 bbl/d (Q4 2018 – 1,265 bbl/d). Production from the two (2.0 net) exploratory Clearwater formation multi-lateral horizontal wells at Ukalta combined to average 150 bbl/d in the fourth quarter of 2019.

For the year ended December 31, 2019, production decreased 15% to 8,988 boe/d (22% oil and NGL) compared to 10,594 boe/d (17% oil and NGL) in the prior year. Production peaked in the first quarter of 2019 and then declined for the remainder of the year, as drilling activity at East Edson was deferred pending higher natural gas prices.

During 2019, Perpetual shut-in an average 275 boe/d to take advantage of temporary situations when natural gas could be purchased at minimal cost to satisfy pre-sold volume commitments at attractive margins, resulting in realized revenue of $0.7 million ($0.05/Mcf) while retaining reserves for future production. Average annual natural gas production decreased 20% to 42.3 MMcf/d (2018 – 52.6 MMcf/d) and NGL production decreased 7% to 719 bbl/d (2018 – 774 bbl/d), reflecting the deferral of its liquids-rich natural gas drilling.

For the year ended December 31, 2019, crude oil production was 1,224 bbl/d, an increase of 17% from the prior year due to the drilling of three (3.0 net) new oil wells and a re-entry to add two additional laterals to an existing oil well at Mannville, combined with initial heavy oil production at Ukalta following the drilling, completion and tie-in of two (2.0 net) wells at the end of the third quarter. Perpetual has continued to focus on waterflood implementation and optimization from 2014 through 2019, with the positive impact of the waterflood evidenced by an overall reduction in decline rates at Mannville.

Commodity Prices

	Three months ended December 31,		Years ended December 31,	
	2019	2018	**2019**	2018
Reference prices				
NYMEX Daily Index (US*$/MMBtu*)	**2.50**	3.64	**2.63**	3.09
AECO Daily Index (*$/GJ*)	**2.35**	1.48	**1.67**	1.42
AECO Daily Index *($/Mcf)*(1)	**2.48**	1.56	**1.76**	1.50
Alberta Gas Reference Price (*$/GJ*)(2)	**2.01**	1.50	**1.40**	1.29
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**56.96**	58.81	**57.03**	64.77
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(15.83)**	(39.42)	**(12.76)**	(26.31)
WCS average (*Cdn$/bbl*)(3)	**54.29**	25.59	**58.88**	50.00
Average Perpetual prices				
Natural gas (*$/Mcf*)(1)				
AECO Daily Index	**2.48**	1.56	**1.76**	1.50
Heat Content Premium(4)	**0.27**	0.17	**0.19**	0.16
Market Diversification Contract	**(0.05)**	1.64	**0.64**	1.02
Realized gains (losses) on financial and physical gas derivatives(6)	**(0.56)**	0.84	**0.16**	0.26
Realized gains (losses) on prompt month price optimization	**(0.14)**	0.17	**0.02**	0.11
Realized natural gas price (*$/Mcf*)(5)	**2.00**	4.38	**2.77**	3.05
Percent of AECO Daily Index	**81%**	281%	**157%**	203%
Realized oil price (*$/bbl*)(5)	**43.85**	19.83	**44.87**	40.62
Realized natural gas liquids ("NGL") price (*$/bbl*)(5)	**43.93**	35.73	**41.01**	52.96

(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$1.32 for the three months ended December 31, 2019 (Q4 2018 – $1.32) and $1.33 for the year ended December 31, 2019 (2018 – $1.30).
(4) Realized natural gas prices are at a premium to the AECO Daily Index due to higher average heat content of 1.17 GJ/Mcf. For the three months and year ended December 31, 2019, Perpetual received an 11% premium to the AECO Daily Index (three months and year ended December 31, 2018 – 11%) related to its higher average heat content.
(5) Realized natural gas, oil and NGL 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.
(6) Includes proceeds of $2.7 million ($0.17/Mcf) for the year ended December 31, 2019 received from the monetization of the Company's market diversification contract for the December 2019 to October 2020 period.

Despite US natural gas production growing by 7.3 Bcf/d from 2018 to 2019, increased demand from LNG exports from the US Gulf Coast and Northeast, as well as pipeline exports to Mexico, resulted in NYMEX natural gas prices decreasing by 15% from US$3.09/MMBtu in 2018 to an average of US$2.63/MMBtu in 2019. For the fourth quarter of 2019, NYMEX natural gas prices averaged US$2.50/MMBtu, down 31% from the prior year period as heating demand was reduced due to unseasonably warm temperatures experienced in the fourth quarter of 2019. In comparison, the AECO Daily Index price increased 18% from $1.42/GJ in 2018 to $1.67/GJ in 2019. In the fourth quarter of 2019, the Canadian Energy Regulator approved TC Energy's Temporary Service Protocol ("TSP") procedures for October 2019 and the April through October 2020 period. TSP prioritized interruptible delivery and storage transportation service over firm transportation receipt service on the NGTL system during maintenance restrictions. The result was a significant increase in AECO prices beginning October 2019.

Perpetual's realized natural gas price, including derivatives, decreased 54% to $2.00/Mcf in the fourth quarter of 2019 from $4.38/Mcf in the comparative period of 2018, and was only 81% of the AECO Daily Index price compared to 281% in the prior year period. The market diversification contract reduced the realized gas price by $0.05/Mcf (Q4 2018 – increase of $1.64/Mcf) on the relative weakness of NYMEX Daily Index prices compared to AECO during the quarter, while AECO-NYMEX basis hedging losses and prompt month optimization contracts reduced the realized gas price by a further $0.70/Mcf. Market diversification contract sales commenced at 35,000 MMBtu/d on November 1, 2017, increasing to 40,000 MMBtu/d on April 1, 2018, expiring October 31, 2024. Pricing is based on daily index prices at five pricing hubs (Chicago, Malin, Dawn, Michcon and Empress) until October 31, 2022 and three pricing hubs (Malin, Dawn and Emerson) from November 1, 2022 to October 31, 2024. These pricing hubs are located outside of Alberta and generally track North American NYMEX prices. During the fourth quarter of 2019, the average heat content conversion ratio for Perpetual's natural gas production was 1.17 GJ:1 Mcf, unchanged from the comparative period of 2018. Natural gas production from East Edson yields higher heat content gas compared to Perpetual's other production areas.

For the year ended December 31, 2019, Perpetual's realized natural gas price was $2.77/Mcf, down 9% from $3.05/Mcf in 2018. Perpetual's realized natural gas price in 2019 was 57% ($1.01/Mcf) higher than the AECO Daily Index price compared to a 103% ($1.55/Mcf) premium realized in 2018. The market diversification contract added $0.64/Mcf (2018 – $1.02/Mcf) on the relative strength of daily index prices at the five downstream markets compared to the AECO Daily Index. In response to TC Energy's changes to TSP maintenance operating protocols that were implemented early in the fourth quarter, Perpetual modified its market diversification contract to shift the pricing point back to AECO for the December 2019 to October 2020 period, and recorded a realized gain of $2.7 million ($0.17/Mcf).

WTI light oil prices decreased by 12% from US$64.77/bbl in 2018 to US$57.03/bbl in 2019 due to a number of factors. Bullish factors including the re-established Iranian supply restrictions implemented by the US; drone strikes on Saudi Arabian oil infrastructure in September 2019; agreement on Phase 1 of a trade deal with China; and escalation of geopolitical tensions between the US and Iran in December 2019, were not enough to fully counter the bearish factors which included gradual increases in global oil production and inventories during 2019; worries about a lengthy trade war between the US and China; and OPEC spare production capacity due to the continued supply restrictions implemented by OPEC.

Perpetual's realized oil price for the fourth quarter of 2019 was $43.85/bbl, 121% higher than the fourth quarter of 2018 despite realized losses on crude oil derivative contracts of $0.7 million ($6.18/bbl). Realized prices in the fourth quarter of 2018 were reduced by $0.44/bbl associated with realized hedging losses in the period. The increase in realized prices was due to the substantial narrowing of the WCS differential to US$15.83/bbl from US$39.42/bbl in the fourth quarter of 2018, which far outweighed the 3% decrease in WTI benchmark pricing over the same period. In early 2019, WCS differentials narrowed significantly due to increased crude by rail transport volumes and the implementation of temporary oil production restrictions by the Government of Alberta which reduced storage volumes and alleviated oil pipeline capacity issues. The volume restrictions were significantly reduced over the course of 2019 as Western Canadian storage levels decreased and differentials stabilized.

For the year ended December 31, 2019, Perpetual's realized oil price was $44.87/bbl, up 10% from $40.62/bbl in 2018. The increase was due to the narrowing of the WCS differential to US$12.76/bbl (2018 – US$26.31/bbl) which more than exceeded the 12% decrease (US$7.74/bbl) in WTI light oil prices. Realized oil prices were reduced by $8.74/bbl associated with realized hedging losses during the year (2018 – realized hedging losses of $2.16/bbl).

Perpetual's realized NGL price for the fourth quarter of 2019 was $43.93/bbl, up 23% from the fourth quarter of 2018, reflecting an increase in all NGL component prices relative to Cdn$ WTI as delays in starting up the North Montney natural gas pipeline reduced anticipated NGL supply, thereby improving prices. Perpetual's average NGL sales composition for the fourth quarter of 2019 improved to 64% condensate compared to 58% in the prior year period.

For the year ended December 31, 2019, Perpetual's realized NGL price was $41.01/bbl, down 23% from $52.96/bbl in 2018, correlating with the 12% decrease in WTI prices over the same period. Approximately 63% of Perpetual's NGL production is comprised of condensate (2018 – 60%) which typically tracks light oil prices.

Revenue

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Petroleum and natural gas revenue				
Natural gas[1]	**7,263**	16,734	**39,318**	54,769
Oil[1]	**5,867**	2,427	**23,958**	16,390
NGL	**2,700**	2,349	**11,085**	14,969
Petroleum and natural gas revenue	**15,830**	21,510	**74,361**	86,128
Realized gains (losses) on derivatives[2]	**(1,495)**	1,287	**(789)**	3,071
Realized revenue	**14,335**	22,797	**73,572**	89,199
Unrealized gains (losses) on derivatives	**(3,369)**	10,885	**(21,893)**	5,747
Total revenue	**10,966**	33,682	**51,679**	94,946
Realized revenue *($/boe)*	**19.50**	26.11	**22.43**	23.07
Total revenue *($/boe)*	**14.92**	38.57	**15.75**	24.55

(1) Includes revenues related to the market diversification contract and physical forward sales contracts which settled during the period.
(2) Includes realized gains (losses) on financial derivatives and certain financial prompt month price optimization contracts. Includes proceeds of $2.7 million ($0.17/Mcf) for the year ended December 31, 2019 received from the monetization of the Company's market diversification contract for the December 2019 to October 2020 period.

Realized revenue was $14.3 million in the fourth quarter of 2019, down 37% from the prior year period due to the 16% decrease in production combined with a 25% decrease in realized revenue per boe. For the fourth quarter of 2019, Perpetual recorded $1.5 million of realized losses on derivatives, comprised of $0.5 million from natural gas hedges and $1.0 million from crude oil and NGL hedges.

For the year ended December 31, 2019, realized revenue was $73.6 million, down 18% from the prior year as a result of the 15% decrease in production combined with a 3% decrease in realized revenue per boe. For the year ended December 31, 2019, Perpetual recorded $0.8 million of realized losses on derivatives, comprised of $3.4 million of gains on natural gas hedges which were more than offset by losses of $4.2 million from crude oil and NGL hedges.

Natural gas revenue, before derivatives, of $7.3 million in the fourth quarter of 2019 comprised 46% (Q4 2018 – 78%) of total P&NG revenue while natural gas production was 76% (Q4 2018 – 78%) of total production. Natural gas revenue decreased 57% from $16.7 million in the fourth quarter of 2018, reflecting significantly lower realized natural gas prices combined with an 18% decrease in natural gas production volumes driven by natural declines following limited capital investment targeting liquids-rich natural gas development in 2019. For the year ended December 31, 2019, natural gas revenue decreased by 28% compared to the prior year period, due primarily to the 20% decrease in natural gas production. Deliveries under Perpetual's market diversification contract contributed losses of $0.2 million ($0.05/Mcf) relative to the AECO Daily Index price in the quarter and contributed revenue of $9.9 million for the year ended December 31, 2019 ($0.64/Mcf). For the three months and year ended December 31, 2018, the market diversification contract contributed revenue of $6.8 million ($1.64/Mcf) and $19.5 million ($1.02/Mcf) respectively.

Oil revenue of $5.9 million represented 37% (Q4 2018 – 11%) of total P&NG revenue while oil production was 16% (Q4 2018 – 14%) of total production. Oil revenue was 142% higher than the same period in 2018 due to the 121% increase in realized oil prices, as crude oil production was unchanged from the prior year period. The higher WCS average reference price of $54.29/bbl was the result of a 60% narrowing of the WCS differential compared to the prior year period, more than offsetting the 3% decrease to US$ WTI benchmark prices. For the year ended December 31, 2019, oil revenue increased by 46% due to the 17% increase in crude oil production in combination with an 18% increase in WCS average prices.

NGL revenue for the fourth quarter of 2019 of $2.7 million comprised 17% (Q4 2018 – 11%) of total P&NG revenue while NGL production represented only 8% (Q4 2018 – 8%) of total Company production. NGL revenue increased by 15% over the prior year period, reflecting the 23% increase in realized NGL prices which more than offset the 15% decrease in NGL production over the same period. For the year ended December 31, 2019, NGL revenue decreased by 26% due to the 7% decrease in NGL production combined with a 23% decrease in realized NGL prices over the prior year. The decrease in NGL production reflected lower natural gas production at East Edson, partially offset by improved NGL yields following the installation of field compression equipment and a sweetening tower to restore higher liquids ratio natural gas wells back to production in the first half of 2019. East Edson production declines have been impacted by the Company's decision to defer liquids-rich gas drilling in response to lower Western Canadian natural gas prices.

Unrealized losses on derivatives of $3.4 million were recorded in the fourth quarter of 2019 (Q4 2018 – unrealized gain of $10.9 million). Unrealized gains and losses represent the change in mark-to-market value of derivative contracts as forward commodity prices and foreign exchange rates change. Unrealized gains and losses on derivatives are excluded from the Corporation's calculation of cash flow from operating activities as they are non-cash. Derivative gains and losses vary depending on the nature and extent of derivative contracts in place, which in turn, vary with the Corporation's assessment of commodity price risk, committed capital spending and other factors.

Royalties

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Crown	**838**	496	**2,313**	2,497
Freehold and overriding[(1)]	**2,545**	1,787	**8,947**	8,097
Total	**3,383**	2,283	**11,260**	10,594
Crown (*% of P&NG revenue*)	**5.3**	2.3	**3.1**	2.9
Freehold and overriding (*% of P&NG revenue*)	**16.1**	8.3	**12.0**	9.4
Total (*% of P&NG revenue*)	**21.4**	10.6	**15.1**	12.3
$/boe	**4.60**	2.61	**3.43**	2.74

(1) Includes $1.9 million in gross overriding royalty payments at East Edson for the three months ended December 31, 2019 (Q4 2018 – $1.2 million) and $5.7 million for the year ended December 31, 2019 (2018 – $5.3 million).

Royalty expense for the fourth quarter of 2019 was $3.4 million, representing 21.4% of P&NG revenue (Q4 2018 – 10.6%) and up 48% from $2.3 million in the prior year period. Higher royalty rates reflect the increase in the Alberta Gas Reference Price and the AECO Daily Index price compared to the prior year period which are used to determine crown royalty and freehold and overriding royalty expense, respectively. At the East Edson property in West Central Alberta, the gross overriding royalty is equivalent to a maximum 5.6 MMcf/d of natural gas and associated NGL production. As West Central natural gas production has decreased by 16% compared to the fourth quarter of 2018, the fixed nature of the gross overriding royalty has resulted in an increased expense on a percentage of revenue and unit-of-production basis.

On an annual basis, royalty expense for 2019 was $11.3 million, representing 15.1% of P&NG revenue (2018 – 12.3%) and up 6% from $10.6 million in the prior year period. Average crown royalty rates increased to 3.1% in 2019 compared to 2.9% in 2018, due primarily to the impact of higher Alberta Gas Reference Prices compared to the prior year as well as the higher percentage of heavy oil in the production mix. Freehold and overriding royalties also increased as a percentage of P&NG revenue from 9.4% to 12.0%, as the AECO Daily Index increased 18% to $1.67/GJ (2018 - $1.42/GJ). In addition, as East Edson production decreased in 2019, the fixed volume nature of the gross overriding royalty resulted in an increased expense as a percentage of revenue and on a unit-of-production basis, which also contributed to the increased overriding royalty rate in 2019.

Production and operating expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Production and operating expenses	**3,839**	4,851	**18,332**	19,229
$/boe	**5.22**	5.56	**5.59**	4.97

Production and operating expenses decreased 21% to $3.8 million in the fourth quarter of 2019 compared to $4.9 million recorded during the same period in 2018 due to reduced costs in Eastern Alberta associated with maintenance activities and the absence of remediation costs from the 2018 Mannville produced water spill. Production and operating expenses per boe decreased by 6% from the prior year period, as lower production and operating costs were partially offset by the 16% decrease in production.

On an annual basis, production and operating expenses decreased 5% to $18.3 million in 2019 compared to $19.2 million in 2018. This decrease reflected remediation and additional water hauling costs of $1.0 million incurred in the third and fourth quarters of 2018 from the Mannville produced water spill. Production and operating expenses averaged $2.74/boe at West Central compared to $16.84/boe at Eastern Alberta, due to the higher cost nature of Eastern Alberta heavy oil production, including waterflood operations at Mannville. In addition, extremely high property taxes related to mature assets contributed $2.32/boe to operating costs in Eastern Alberta in 2019.

Transportation costs

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Transportation costs	**1,551**	1,489	**6,258**	6,068
$/boe	**2.11**	1.71	**1.91**	1.57

Transportation costs include clean oil trucking and NGL transportation as well as costs to transport natural gas from the plant gate to commercial sales points. For the fourth quarter of 2019, transportation costs were $1.6 million, comparable with the fourth quarter of 2018. On a unit-of-production basis, company-wide transportation costs increased by 23% from $1.71/boe in the fourth quarter of 2018 to $2.11/boe in the same period of 2019, due to the impact of unutilized demand charges from firm natural gas pipeline capacity at East Edson combined with the 16% decrease in production. Transportation costs averaged $1.64/boe at West Central compared to $3.80/boe for production from Eastern Alberta.

For the year ended December 31, 2019, transportation costs were $6.3 million, an increase of 3% over 2018. The increase was due to higher per unit trucking costs in Eastern Alberta, where crude oil production increased by 19% year-over-year.

Gas over bitumen

($ thousands, except as noted)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
Gas over bitumen royalty credit	**202**	302	**852**	1,046
Payments of gas over bitumen royalty financing(1)	**(225)**	(257)	**(1,013)**	(1,135)
Gas over bitumen, net of payments	**(23)**	45	**(161)**	(89)
$/boe	**(0.03)**	0.05	**(0.05)**	(0.02)

(1) At December 31, 2019, the fair value of the remaining gas over bitumen royalty financing obligation is estimated to be $0.9 million (2018 – $1.1 million).

Perpetual records revenue in relation to gas over bitumen royalty credits received under the Natural Gas Royalty Regulation as a result of its working interests in a number of natural gas wells which have been shut-in pursuant to shut-in orders issued by the Government of Alberta. For the year ended December 31, 2019, Perpetual recorded $0.9 million in gas over bitumen revenue, a decrease of 19% from 2018. The decrease was attributable to the annual 10% decline in deemed production, combined with the expiry of certain gas over bitumen royalty credits for wells that were shut-in during the fourth quarter of 2009.

Gas over bitumen royalty credits earned throughout 2019 were offset by payments of $1.0 million (2018 – $1.1 million) in relation to the 2014 monetization of Perpetual's future gas over bitumen royalty credits. The payment commitment expires concurrent with the cessation of the gas over bitumen royalty credit, with final payments expected to occur in June 2021.

Under IFRS, the monetization of future gas over bitumen royalty credits is recorded as a financial obligation ("Gas over bitumen royalty financing"); however, entitlement to future revenues from gas over bitumen royalty credits are not recorded as an asset, but as revenue with the passage of time as it is earned. As such, gas over bitumen royalty credits 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 are included as a reduction to gas over bitumen revenue to reflect the substantive monetization of the future gas over bitumen royalty credits. During the fourth quarter of 2019, the gas over bitumen royalty financing obligation decreased by $0.1 million, comprised of payments of $0.2 million which were partially offset by an unrealized loss of $0.1 million. The loss has been included in non-cash finance expense and represents an increase in the fair value of the gas over bitumen royalty financing obligation during the fourth quarter of 2019, reflecting higher forecast natural gas reference prices based on the AECO forward market.

During 2019, the gas over bitumen royalty financing obligation was reduced by $0.3 million, comprised of payments of $1.0 million (2018 – $1.1 million) which were partially offset by an unrealized loss of $0.7 million (2018 – unrealized gain of $0.5 million). The loss has been included in non-cash finance expense and represents an increase in the fair value of the gas over bitumen royalty financing obligation compared to 2018, as a result of higher forecast natural gas reference prices based on the AECO forward market.

Exploration and evaluation ("E&E") expenses

($ thousands)	Three months ended December 31, 2019	2018	Years ended December 31, 2019	2018
Lease rentals(1)	**52**	132	**190**	649
Geological and geophysical costs	**–**	–	**8**	78
Lease expiries (non-cash)	**759**	1,485	**1,599**	1,485
Total E&E expense	**811**	1,617	**1,797**	2,212

(1) Commencing in the second quarter of 2019, developed mineral lease rentals have been classified as production and operating expenses.

Exploration and evaluation expenses include lease rentals on undeveloped acreage, geological and geophysical costs, and the write-down of carrying costs related to lease expiries. During the fourth quarter of 2019, the Company recorded $0.8 million of non-cash write-downs associated with certain undeveloped lands that were either allowed to expire, or are no longer part of Perpetual's future development plans. For the year ended December 31, 2019, Perpetual recorded $1.6 million of non-cash write-downs associated with undeveloped lands that were allowed to expire (2018 – $1.5 million).

General and administrative ("G&A") expenses

($ thousands, except as noted)	Three months ended December 31, 2019	2018(1)	Years ended December 31, 2019	2018(1)
Cash G&A expense	**2,604**	4,246	**12,808**	15,459
Overhead recoveries	**(198)**	(453)	**(1,148)**	(1,829)
Total G&A expense	**2,406**	3,793	**11,660**	13,630
$/boe	**3.27**	4.34	**3.55**	3.52

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

During the fourth quarter of 2019, cash G&A expense was $2.6 million, a 39% decrease from the prior year period of $4.2 million due primarily to the reduction of approximately 25% of Perpetual's corporate employee head count, combined with a reduction in compensation for remaining employees that was implemented at the end of the third quarter. Fourth quarter 2019 overhead recoveries decreased by 56% relative to the 2018 period due to limited capital spending. On a unit-of-production basis, total G&A expense was down 25% to $3.27/boe for the three months ended December 31, 2019, as lower costs were partially offset by the 16% decline in production compared to the prior year period.

For the year ended December 31, 2019, total G&A expense decreased by 14% over the prior year period, due primarily to cost reductions implemented at the end of the third quarter, partially offset by lower overhead recoveries triggered by the reduction in capital expenditures from $26.9 million in 2018 to $12.9 million in 2019. On a unit-of-production basis, total G&A expense of $3.55/boe for the year ended December 31, 2019 was comparable to the prior year period of $3.52/boe, as the decrease in production was almost completely offset by lower overall costs.

Restructuring costs

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Restructuring costs	**–**	–	**1,546**	–

In response to the decrease in forward commodity prices, the Company implemented a restructuring plan at the end of the third quarter which resulted in the reduction of approximately 25% of Perpetual's corporate employee head count. Restructuring costs of $1.5 million were expensed in the third quarter of 2019, of which $0.6 million was paid during the fourth quarter and $0.9 million is anticipated to be fully paid by the end of 2020. Annual cost savings of $3.5 million are anticipated, commencing in the fourth quarter of 2019.

Share-based payments

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018	**2019**	2018
Share-based payments (non-cash)	**123**	566	**406**	2,573
Share-based payments (cash)	**365**	–	**1,889**	–
Total share-based payments	**488**	566	**2,295**	2,573

Share-based payments expense for the three months ended December 31, 2019 was $0.5 million, down 14% from the same period in 2018 due to a reduction in the performance multiplier estimate applicable to performance share rights, combined with a reduction in the number of outstanding share-based payment awards. No new awards were granted to employees in the fourth quarter of 2019, while 0.1 million deferred shares were granted to Directors of the Company. For the year ended December 31, 2019, share-based payments expense was $2.3 million, 11% lower than the prior year period for the same reasons noted above.

Depletion and depreciation

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2019**	2018[(1)]	**2019**	2018[(1)]
Depletion and depreciation	**6,960**	7,777	**31,188**	34,946
$/boe	**9.47**	8.91	**9.51**	9.04

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

Perpetual recorded $31.2 million of depletion and depreciation expense for the year ended December 31, 2019, down 11% from $34.9 million in 2018 due to the 15% decrease in production volumes compared to the prior year. On a per boe basis, depletion and depreciation expense of $9.51/boe was 5% higher than the prior year, due primarily to the higher depletion rates associated with the Company's Eastern Alberta assets, which make up a larger percentage of Perpetual's total production on which depletion expense is recorded. The Company's 2019 capital program added proved plus probable reserves that replaced 74% of 2019 production (2018 – 134% of production) at F&D costs of $10.54/boe, including FDC (2018 **–** $5.09/boe).

Impairment

In accordance with IFRS, an impairment test is performed if the Company identifies an indicator of impairment. For the quarter ended December 31, 2019, the Company conducted an assessment of impairment indicators for the Company's CGUs. In performing the review, management determined that the considerable economic instability and uncertainty in the oil and natural gas markets which negatively impacts operating cash flows, coupled with the Company's available liquidity at December 31, 2019, justified calculation of the recoverable amount of the liquids-rich natural gas assets which comprise the West Central CGU. The recoverable amount of the West Central CGU was determined using value-in-use ("VIU") based on the net present value of cash flows from oil, natural gas, and NGL reserves using estimates of total proved plus probable reserves evaluated or reviewed by the Company's independent reserves evaluators, along with commodity price estimates based on an average of three independent reserve evaluators, and an estimate of market discount rates between 10% and 22% to consider risks specific to the asset.

At December 31, 2019, the Company determined that the carrying amount of the West Central CGU exceeded the recoverable amount of $130.8 million and accordingly, an impairment charge of $23.8 million was included in net loss.

During the fourth quarter of 2019, the Company decommissioned its Panny natural gas properties due to an excessive property tax burden and determined that the associated $0.7 million carrying value was no longer recoverable. Accordingly, a $0.7 million impairment charge was included in net loss.

At June 30, 2019, the Company determined that the carrying amount of the West Central CGU exceeded the recoverable amount of $165.0 million and accordingly, an impairment charge of $22.6 million was included in net loss.

Finance expenses

($ thousands)	Three months ended December 31, **2019**	2018	Years ended December 31, **2019**	2018
Cash finance expense				
Interest on revolving bank debt	**788**	633	**2,880**	2,226
Interest on TOU share margin demand loan	**72**	130	**407**	570
Interest on term loan	**936**	936	**3,645**	3,665
Interest on senior notes	**735**	710	**2,921**	2,864
Interest on lease liabilities(1)	**44**	–	**189**	–
Dividend income from TOU share investment	**(199)**	(167)	**(762)**	(618)
Total cash finance expense	**2,376**	2,242	**9,280**	8,707
Non-cash finance expense				
Amortization of debt issue costs	**326**	262	**1,187**	1,026
Accretion on decommissioning obligations	**162**	216	**752**	841
Change in fair value of gas over bitumen royalty financing	**117**	(414)	**732**	(452)
Total non-cash finance expense	**605**	64	**2,671**	1,415
Finance expenses recognized in net loss	**2,981**	2,306	**11,951**	10,122

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

Total cash finance expense was $2.4 million in the fourth quarter of 2019, 6% higher than the prior year period. The change was due to increased interest expense on the revolving Credit Facility associated with higher floating interest rates, increased borrowing amounts associated with the partial repayment of the TOU share margin demand loan during the second half of 2019, and a higher principal amount of senior notes outstanding as a result of the senior note refinancing completed in June 2019. Increased interest on revolving bank debt was partially offset by lower interest on the TOU share margin demand loan and higher dividend income from the Company's TOU share investment. On an annual basis, total cash finance expense was $9.3 million, up $0.6 million from 2018 for the same reasons noted above. Credit Facility borrowing costs have increased by 1% as a result of the borrowing base redetermination that was completed in late December.

Total non-cash finance expense for the three months ended December 31, 2019 was $0.6 million, up $0.5 million from 2018. The increase was due primarily to the change in fair value of the gas over bitumen royalty financing, which resulted in an unrealized loss of $0.1 million during the fourth quarter of 2019 compared to an unrealized gain of $0.4 million in 2018. The loss represents an increase in the fair value of the gas over bitumen royalty financing obligation compared to 2018, as a result of higher forecast natural gas reference prices based on the AECO forward market. For the year ended December 31, 2019, non-cash finance expense was $2.7 million, 89% higher than the prior year period and again caused by the change in fair value of the gas over bitumen royalty financing.

Change in fair value of TOU share investment

In December 2019, the Company sold 656,773 TOU shares at a weighted average price of $14.78 per share, for net cash proceeds of $9.7 million. Proceeds from the sale of TOU shares were used to pay down the balance of the TOU share margin demand loan by $9.1 million. The remaining proceeds were used to repay Credit Facility borrowings.

At December 31, 2019, the Company held 1.0 million (December 31, 2018 – 1.66 million shares) TOU shares with a fair market value of $15.2 million (December 31, 2018 – $28.1 million). For the year ended December 31, 2019, Perpetual recorded an unrealized loss of $3.2 million related to the change in fair value of the TOU share investment, which represents the change in value of TOU shares held from December 31, 2018 ($16.98 per share) to December 31, 2019 ($15.22 per share).

In January 2020, the Company sold its remaining 1,000,000 TOU shares at a weighted average price of $14.32 per share, for net cash proceeds of $14.3 million. Net proceeds were used to repay the remaining $0.1 million TOU share margin demand loan, with the balance used to repay a portion of the Credit Facility.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Perpetual's strategy targets the maintenance of 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, available liquidity, 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, and net working capital. To manage its capital structure and available liquidity, the Company may from time to time issue equity or debt securities, sell assets, and adjust its capital spending to manage current and projected debt levels. The Company will continue to regularly assess changes to its capital structure and repayment alternatives, with considerations for both short-term liquidity and long-term financial sustainability.

Capital Management

($ thousands, except as noted)	**December 31, 2019**	December 31, 2018
Revolving bank debt	**47,552**	42,561
Term loan, principal amount	**45,000**	45,000
TOU share margin demand loan, principal amount	**100**	14,144
Senior notes, principal amount	**33,580**	32,490
TOU share investment(1)	**(15,220)**	(28,132)
Net working capital deficiency(2)	**7,068**	6,543
Net debt(2)	**118,080**	112,606
Shares outstanding at end of period (*thousands*)(3)	**60,513**	60,240
Market price at end of period (*$/share*)(3)	**0.07**	0.20
Market value of shares	**4,236**	12,048
Enterprise value(2)	**122,316**	124,654
Net debt as a percentage of enterprise value	**97**	90
Trailing twelve months adjusted funds flow(2)	**14,534**	30,155
Net debt to trailing twelve months adjusted funds flow	**8.1**	3.7

(1) The TOU share investment is based on the December 31, 2019 closing price per the Toronto Stock Exchange ($15.22 per share) and 1.0 million TOU shares held (December 31, 2018 – 1.66 million TOU shares held with a closing price of $16.98 per share).
(2) See "Non-GAAP measures" in this MD&A.
(3) Shares outstanding are presented net of shares held in trust.

At December 31, 2019, Perpetual had total net debt of $118.1 million, up $5.5 million (5%) from December 31, 2018. The increase was due primarily to a $3.2 million decrease in the fair value of the TOU share investment during 2019, combined with an incremental $1.1 million of 2022 Senior Notes that were issued in connection with the early redemption of the 2019 Senior Notes in the second quarter. Revolving bank debt increased by $5.0 million during 2019 to $47.6 million at December 31, 2019 due to a $5.0 million repayment of the TOU share margin demand loan during the year.

As at December 31, 2019, 67% of net debt outstanding was repayable in 2021 or later. Perpetual's net debt to trailing twelve months adjusted funds flow increased to 8.1 times at December 31, 2019 (December 31, 2018 – 3.7 times).

TOU share margin demand loan

At December 31, 2019, Perpetual had a $0.1 million non-revolving TOU share margin demand loan secured by 1.0 million TOU shares. 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.

In December 2019, Perpetual sold 656,773 TOU shares at a weighted average price of $14.78 per share and used the proceeds of $9.7 million to partially repay the TOU share margin demand loan. Total loan repayments of $14.0 million were made during 2019. In January 2020, the Company sold its remaining 1,000,000 TOU shares for net cash proceeds of $14.3 million. Net proceeds were used to fully repay the TOU share margin demand loan and to repay a portion of the Credit Facility.

Revolving bank debt

As at December 31, 2019, the Company's Credit Facility had a Borrowing Limit of $55.0 million (December 31, 2018 – $55.0 million) under which $47.6 million was drawn (December 31, 2018 – $42.6 million) and $2.3 million of letters of credit had been issued (December 31, 2018 – $3.7 million). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance margins range between 3.0% and 5.5%.

On December 24, 2019, Perpetual's syndicate of Credit Facility lenders completed their semi-annual borrowing base redetermination, reducing the Borrowing Limit from $55 million to $45 million on January 22, 2020, with the maturity date remaining at November 30, 2020. Previously, on March 27, 2019, the Company's lenders confirmed the $55 million Borrowing Limit and the maturity was extended to November 30, 2020. As a result, revolving bank debt has been presented as a current liability on the consolidated statements of financial position as at December 31, 2019.

The next Borrowing Limit redetermination is scheduled on or prior to March 31, 2020. The Credit Facility will revolve until March 31, 2020 and may be extended for a period of up to 364-days subject to approval by the Company's lenders. If not extended, the Credit Facility will cease to revolve, and all outstanding advances will be repayable on November 30, 2020.

The Credit Facility is secured by general, first lien security agreements covering all present and future property of the Company and its subsidiaries, with the exception of certain lands pledged to the gas over bitumen royalty financing counterparty. The Credit Facility also contains provisions which restrict the Company's ability to repay second lien and unsecured debt and to pay dividends on or repurchase its common shares.

The effective interest rate on the Credit Facility at December 31, 2019 was 7.5% (December 31, 2018 – 6.2%). If interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net loss would be $0.5 million.

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

Term loan

			December 31, 2019		December 31, 2018	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	March 14, 2021	8.1%	**$ 45,000**	**$ 44,274**	$ 45,000	$ 43,729

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

The term loan has a cross-default provision with the Credit Facility and contains substantially similar 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, and certain lands pledged to the gas over bitumen royalty financing counterparty.

At December 31, 2019, the term loan is presented net of $0.7 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 9.5%.

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

Senior notes

			December 31, 2019		December 31, 2018	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 Senior Notes	July 23, 2019	8.75%	**$ –**	**$ –**	$ 14,572	$ 14,536
2022 Senior Notes	January 23, 2022	8.75%	**33,580**	**32,255**	17,918	17,344
			$ 33,580	**$ 32,255**	$ 32,490	$ 31,880

On May 7, 2019, Perpetual announced the early redemption of all of the $14.6 million aggregate principal amount of 8.75% senior notes maturing July 23, 2019 (the “2019 Senior Notes”) effective June 11, 2019 (the "Redemption Date"). Pursuant to the early redemption, holders of the 2019 Senior Notes would receive CDN $1,000 for each $1,000 principal amount of 2019 Senior Notes (the "Cash Consideration"); or, at the election of the holder, $1,075 principal amount of 8.75% senior notes due January 23, 2022 (the “2022 Senior Notes”) for each $1,000 principal amount of 2019 Senior Notes (the "2022 Senior Notes Consideration") plus cash in the amount of $33.32 per $1,000 principal amount of 2019 Senior Notes, representing all accrued and unpaid interest at the Redemption Date.

On June 11, 2019, the Company completed the early redemption of the $14.6 million 2019 Senior Notes. Pursuant to the early redemption, the Company issued $15.7 million of 2022 Senior Notes to fully redeem the 2019 Senior Notes, of which $15.6 million 2022 Senior Notes were issued to entities controlled by or associated with the Company’s CEO. There was no gain or loss on the exchange. After giving effect to this senior note refinancing, there are $33.6 million 2022 Senior Notes outstanding comprised of $17.9 million 2022 Senior Notes previously outstanding, and the $15.7 million 2022 Senior Notes issued as consideration to redeem the 2019 Senior Notes. Entities controlled by the Company’s CEO hold $13.4 million of the 2022 Senior Notes now outstanding. An entity that is associated with the Company’s CEO holds an additional $9.1 million of the 2022 Senior Notes now outstanding.

The 2022 Senior Notes bear a fixed interest rate of 8.75% with semi-annual interest payments due January 23 and July 23 of each year. 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. Prior to January 23, 2021, the Company may redeem up to 100% of the senior notes at 103.3% of the principal amount. Subsequent to January 23, 2021, the Company may redeem up to 100% of the senior notes at the principal amount.

At December 31, 2019, the 2022 Senior Notes are recorded at the present value of future cash flows, net of issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 10.9%.

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.

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

Equity

At December 31, 2019 there were 60.5 million common shares outstanding, net of 0.8 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended December 31, 2019 were 60.4 million (Q4 2018 – 60.4 million) and 60.3 million for the year ended December 31, 2019 (2018 – 60.0 million).

At March 18, 2020 there were 60.7 million common shares outstanding which is net of 0.6 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)	**March 18, 2020**
Share options	**4.6**
Performance share rights[1]	**2.7**
Compensation awards[1]	**4.7**
Total	**12.0**

(1) 2.7 million performance share rights have an exercise price below the December 31, 2019 closing price of the Company's common shares of $0.07 per share.

Contractual obligations

At December 31, 2019, the Company's minimum contractual obligations over the next five years and thereafter, excluding estimated interest payments are as follows:

	2020	**2021**	**2022**	**2023**	**2024 and thereafter**	**Total**
Contractual obligations						
Accounts payable and accrued liabilities	13,278	–	–	–	–	13,278
Fair value of derivative liabilities	10,542	2,732	–	–	–	13,274
TOU share margin demand loan, principal amount	100	–	–	–	–	100
Revolving bank debt	47,552	–	–	–	–	47,552
Term loan, principal amount	–	45,000	–	–	–	45,000
Senior notes, principal amount	–	–	33,580	–	–	33,580
Gas over bitumen royalty financing	582	289	–	–	–	871
Lease liabilities	633	567	492	460	533	2,685
Pipeline transportation commitments	3,030	1,870	945	945	945	7,735
Total	**75,717**	**50,458**	**35,017**	**1,405**	**1,478**	**164,075**

The Company anticipates that it will require additional financing or a potential refinancing plan to address the anticipated liquidity shortfall and the upcoming debt maturities. Perpetual is considering options including arranging for extensions of the debt maturity dates, alternative refinancing or additional financing arrangements, or the sale or monetization of other assets. Refer to the future operations section of this MD&A.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q4 2019**	Q3 2019	Q2 2019	Q1 2019
Financial				
Oil and natural gas revenue	**15,830**	17,097	19,235	22,199
Net loss	**(32,498)**	(20,349)	(36,276)	(4,892)
Per share – basic and diluted	**(0.54)**	(0.34)	0.60)	(0.08)
Cash flow from (used in) operating activities	**(1,290)**	5,509	4,295	9,292
Adjusted funds flow[1]	**340**	4,183	3,649	6,362
Per share – basic and diluted	**0.01**	0.07	0.06	0.11
Capital expenditures	**1,995**	4,506	5,200	1,238
Net payments (proceeds) on acquisitions and dispositions	**–**	–	–	–
Net capital expenditures	**1,995**	4,506	5,200	1,238
Common shares *(thousands)*				
Weighted average – basic and diluted	**60,444**	60,317	60,154	60,111
Operating				
Daily average production				
Natural gas *(MMcf/d)*	**36.6**	38.2	44.5	50.0
Oil *(bbl/d)*	**1,275**	1,292	1,207	1,121
NGL *(bbl/d)*	**606**	731	754	785
Total *(boe/d)*	**7,991**	8,383	9,370	10,240
Average prices				
Realized natural gas price *($/Mcf)*[2]	**2.00**	3.13	2.25	3.54
Realized oil price *($/bbl)*[2]	**43.85**	44.31	50.01	41.12
Realized NGL price *($/bbl)*[2]	**43.93**	37.34	51.34	32.16

($ thousands, except where noted)	Q4 2018[3]	Q3 2018[3]	Q2 2018[3]	Q1 2018[3]
Financial				
Oil and natural gas revenue	21,510	20,504	20,774	23,340
Net loss	(331)	(12,259)	(1,325)	(6,465)
Per share – basic and diluted	(0.01)	(0.20)	(0.02)	(0.11)
Cash flow from operating activities	5,163	6,729	8,435	11,198
Adjusted funds flow[1]	8,052	5,155	7,847	9,101
Per share – basic	0.13	0.09	0.13	0.15
Net capital expenditures				
Capital expenditures	5,617	4,343	2,031	14,897
Net payments (proceeds) on acquisitions and dispositions	(1,285)	4,341	(7,012)	926
Net capital expenditures	4,332	8,684	(4,981)	15,823
Common shares (*thousands*)				
Weighted average – basic and diluted	60,448	60,468	59,876	59,345
Operating				
Daily average production				
Natural gas (*MMcf/d*)	44.9	46.9	53.1	65.9
Oil (*bbl/d*)	1,301	1,022	971	900
NGL (*bbl/d*)	715	730	806	848
Total (*boe/d*)	9,491	9,569	10,620	12,742
Average prices				
Realized natural gas price (*$/Mcf*)[2]	4.38	2.83	2.62	2.65
Realized oil price (*$/bbl*)[2]	19.83	48.57	53.26	48.31
Realized NGL price (*$/bbl*)[2]	35.73	56.02	60.77	57.61

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

The Company's oil and natural gas revenue, net loss, cash flow from (used in) operating activities and adjusted funds flow are influenced by commodity prices and production levels. Natural gas production levels decreased during 2018 and 2019 due to natural declines and reduced capital expenditures in response to depressed AECO natural gas prices, and due to the shut-in of approximately 700 boe/d of production during the second, third and fourth quarters of 2018 at East Edson associated with the Sequoia bankruptcy. This production was restarted in mid-December 2018, causing natural gas production to increase temporarily in the first quarter of 2019. Oil-focused capital expenditures increased in the second and third quarters of 2019, as improved oil prices and differentials supported investment.

The net loss for the fourth quarter of 2019 was $32.5 million ($0.54/share). The Company recognized impairment charges of $22.6 million and $24.5 million in the second and fourth quarters of 2019, respectively, along with $1.5 million of restructuring costs during the third quarter of 2019.

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 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 March 18, 2020:

Natural Gas

The Company has open physical and financial basis differential contracts between AECO and NYMEX. Settlements on physical sales contracts are recognized in oil and natural gas revenue.

Term	**Volumes sold (bought)** *(MMBtu/d)*	**AECO-NYMEX differential** *(US$/MMBtu)*[1]	**Market prices** *(US$/MMBtu)*[2]	**Type of contract**
January 2020 – December 2020	12,500	(1.41)	(0.58)	Physical
January 2020 – December 2020	15,000	(1.41)	(0.58)	Financial
January 2021 – December 2021	15,000	(1.31)	(0.84)	Physical

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for January, February and March 2020 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 March 18, 2020.

Crude Oil

The Company had entered into the following financial fixed price oil sales arrangements which settle in US$ as follows:

Term	**Volumes** *(bbl/d)*	**WTI average price** *(US$/bbl)*	**Market prices** *(US$/bbl)*[1]	**Type of contract**
January 2020 – October 2020	100	57.90	30.05	Financial
January 2020 – December 2020	750	53.07	29.68	Financial

(1) Market prices for January and February 2020 are based on settled WTI oil prices. Market prices for subsequent months are based on forward WTI oil prices as of market close on March 18, 2020.

The following table provides a summary of basis differential contracts between WTI and WCS:

Term	**Volumes** *(bbl/d)*	**WTI-WCS differential** *(US$/bbl)*[1]	**Market prices** *(US$/bbl)*[2]	**Type of contract**
January 2020 – December 2020	750	(18.75)	(15.99)	Financial
March 2020 – October 2020	100	(17.65)	(14.63)	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 January, February and March 2020 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 March 18, 2020.

The following table provides a summary of WCS fixed price contracts which settle in Cdn$:

Term	**Volumes** *(bbl/d)*	**WCS average price** *($/bbl)*	**Market prices** *($/bbl)*[1]	**Type of contract**
January 2020 – December 2020	250	50.00	21.13	Financial

(1) Market prices for January and February 2020 are based on settled WCS oil prices. Market prices for subsequent months are based on forward WCS oil prices as of market close on March 18, 2020.

NGL

The following table provides a summary of financial NGL basis differential arrangements between WTI and Edmonton condensate pricing:

Term	**Volumes** *(bbl/d)*	**WTI Edmonton condensate differential** *(US$/bbl)*[1]	**Market prices** *(US$/bbl)*[2]	**Type of contract**
January 2020 – June 2020	350	(6.15)	(0.79)	Financial

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for January, February and March 2020 are based on settled WTI Edmonton condensate differential prices. Market prices for subsequent months are based on forward WTI Edmonton condensate differential prices as of market close on March 18, 2020.

Foreign Exchange

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

Term	Notional *(US$ thousands/month)*	Strike rate *(US$/Cdn$)*[1]	Market prices *(US$/Cdn$)*[2]
January 2020 – March 2020	2,000	1.29	1.35

(1) Average price calculated using weighted average price for net open contracts.
(2) Market prices for January and February 2020 are based on settled US$/Cdn$ exchange rates. Market prices for subsequent months are based on forward US$/Cdn$ exchange rates as of market close on March 18, 2020.

Natural Gas Sales Obligations

Natural gas volumes sold pursuant to the Company's market diversification contract are sold at fixed volume obligations of 40,000 MMBtu/d and priced at daily index prices at each of the market price points, less transportation costs from AECO to each market price point as detailed below.

In the third quarter of 2019, Perpetual extended the term of its market diversification contract by two years. From November 1, 2022 to October 31, 2024, Perpetual will deliver 40,000 MMBtu/d at AECO and receive Malin, Dawn, and Emerson daily index prices less US$0.0775/MMBtu and transportation costs from AECO to the market price point.

In late September 2019, the Company modified its market diversification contract to forgo its right to receive pricing at five North American natural gas hub pricing points for the period commencing December 1, 2019 and ending on October 31, 2020 in consideration for receipt of payment of $2.7 million. The amount has been recognized in revenue as a realized gain on derivatives.

Market/Pricing Point	November 1, 2020 to October 31, 2022 Daily sales volume *(MMBtu/d)*	November 1, 2022 to October 31, 2024 Daily sales volume *(MMBtu/d)*
Chicago	12,200	–
Malin	10,800	15,000
Dawn	8,000	15,000
Michcon	5,200	–
Empress	3,800	–
Emerson	–	10,000
Total natural gas sales volume obligation	**40,000**	**40,000**

SELECTED ANNUAL INFORMATION

($ thousands, except where noted)	**2019**	2018[4]	2017[4]
Financial			
Oil and natural gas revenue	**74,361**	86,128	81,722
Net income (loss)	**(94,015)**	(20,380)	(35,971)
Per share – basic and diluted[1]	**(1.56)**	(0.34)	(0.62)
Cash flow from (used in) operating activities	**17,806**	31,525	19,170
Adjusted funds flow	**14,534**	30,155	31,115
Per share[1][2]	**0.24**	0.50	0.54
Total assets	**241,148**	335,089	365,570
Total long-term liabilities	**118,061**	101,870	144,186
Revolving bank debt	**47,552**	42,561	31,581
Senior notes, principal amount	**33,580**	32,490	32,490
Term loan, principal amount	**45,000**	45,000	45,000
TOU share margin demand loan, principal amount	**100**	14,144	18,490
TOU share investment	**(15,220)**	(28,132)	(37,985)
Net working capital deficiency	**7,068**	6,543	16,404
Total net debt	**118,080**	112,606	105,980
Net capital expenditures			
Capital expenditures	**12,939**	26,888	73,035
Net payments (proceeds) on acquisitions and dispositions	**–**	(3,030)	2,422
Net capital expenditures	**12,939**	23,858	75,457
Common shares (*thousands*)			
End of period[3]	**60,513**	60,240	59,263
Weighted average – basic	**60,258**	60,039	58,017
Weighted average – diluted	**60,258**	60,039	58,017
Operating			
Daily average production			
Natural gas (*MMcf/d*)	**42.3**	52.6	49.6
Oil (*bbl/d*)	**1,224**	1,050	948
NGL (*bbl/d*)	**719**	774	655
Total average production (*boe/d*)	**8,988**	10,594	9,876
Average prices			
Realized natural gas price (*$/Mcf*)	**2.77**	3.05	3.51
Realized oil price (*$/bbl*)	**44.87**	40.62	41.62
NGL price (*$/bbl*)	**41.01**	52.96	46.60
Wells drilled			
Natural gas – gross (net)	**– (–)**	1 (1.0)	15 (14.4)
Crude oil – gross (net)	**5 (5.0)**	6 (6.0)	4 (3.3)
Total – gross (net)	**5 (5.0)**	7 (7.0)	19 (17.7)

(1) Based on weighted average common shares outstanding for the year.
(2) See "Non-GAAP measures" in this MD&A.
(3) Reduced by shares held in trust (2019 – 801; 2018 – 661; and 2017 – 447). See "Note 17 to the Audited Consolidated Financial Statements".
(4) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated. Refer to the recently adopted accounting pronouncements section in this MD&A.

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

FUTURE ACCOUNTING PRONOUNCEMENTS

Recently adopted

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

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

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

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

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

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

The adoption of the new standard had the following impact on the Company's financial results for the year ended December 31, 2019, compared to what would have occurred had the new accounting policy not been adopted:

(*$ thousands, except as noted*)	**Decrease (increase) in net loss**	**Impact on net cash flows from (used in) operating activities and adjusted funds flow[1]**
Production and operating expense	93	93
General and administrative expense	335	335
Depletion and depreciation expense	(384)	–
Cash interest on lease liabilities	(189)	(189)
Net IFRS 16 implementation impact	**(145)**	**239**

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

Further information about changes to accounting policies resulting from the adoption of IFRS 16 can be found in Note 3 to the consolidated financial statements.

New standards issued but not yet adopted

In October 2018, the International Accounting Standards Board ("IASB") issued amendments to the definition of a business in IFRS 3 Business Combinations. The amendments are intended to assist entities in determining whether a transaction should be accounted for as a business combination or as an asset acquisition. IFRS 3 continues to adopt a market participant's perspective to determine whether an acquired set of activities and assets is a business. The amendments clarify the minimum requirements for a business; remove the assessment of whether market participants are capable of replacing any missing elements; add guidance to help entities assess whether an acquired process is substantive; narrow the definitions of a business and of outputs; and introduce an optional fair value concentration test.

The amendments to IFRS 3 are effective for annual reporting periods beginning on or after January 1, 2020 and apply prospectively.

CORPORATE GOVERNANCE

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

RISK FACTORS

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

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

Perpetual manages these risks by:

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

A complete discussion of risk factors is included in the Corporation's 2019 Annual Information Form ("AIF") available on the Corporation's website at www.perpetualenergyinc.com or on SEDAR at www.sedar.com.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

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

Disclosure controls and procedures

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

Perpetual's CEO and CFO have concluded, based on their evaluation at December 31, 2019, the DC&P are designed and operating effectively to provide reasonable assurance that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in the securities legislation and include controls and procedures designed to ensure that information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted under securities legislation is accumulated and communicated to the issuer's management, including its certifying officers, as appropriate to allow timely decisions regarding required disclosure.

Management's annual report on internal controls over financial reporting

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

Under the supervision and with the participation of management, including the CEO and CFO, an evaluation of the effectiveness of the internal controls over financial reporting was conducted as of December 31, 2019 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2019, the internal controls over financial reporting were designed and operating effectively.

Changes to internal controls over financial reporting

There were no changes in the Corporation's internal control over financial reporting during the three months ended December 31, 2019 that have materially affected, or are reasonably likely to materially affect, internal control over financial reporting.

CEO and CFO certifications

Perpetual's CEO and CFO have filed with the Canadian securities regulators regarding the quality of Perpetual's public disclosures relating to its fiscal 2019 report filed with the Canadian securities regulators.

CRITICAL ACCOUNTING ESTIMATES

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

- Estimation of recoverable oil and natural gas reserves and future cash flows from reserves;
- Forward market prices;
- Geological interpretations, success or failure of exploration activities, and Perpetual's plans with respect to property and financial ability to hold the property;
- Risk free interest rates;
- Estimation of future abandonment and reclamation costs;
- Facts and circumstances supporting the likelihood and amount of contingent liabilities, including the Sequoia litigation disclosed in Note 8 to the consolidated financial statements; and
- Interpretation of income tax laws.

A change in a critical accounting estimate can have a significant effect on net loss as a result of their impact on the depletion rate, provisions, impairments, losses and income taxes. A change in a critical accounting estimate can have a significant effect on the value of property, plant, and equipment, provisions, derivative financial instruments and accounts payable. A complete discussion of critical accounting estimates is included in the notes to the consolidated financial statements at December 31, 2019.

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 "2020 Guidance" 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 Company's ability to continue as a going concern; 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, crude oil and NGL; 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, NGL and other risk management contracts; net income (loss) and adjusted funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes; production and operating, general and administrative, 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 2020 and 2021; 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.

OIL AND GAS ADVISORIES

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

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

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

CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT

The consolidated financial statements of Perpetual Energy Inc. ("the Company") are the responsibility of Management and have been approved by the Board of Directors of the Company. These consolidated financial statements have been prepared by Management in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and the Interpretations of the IFRS Interpretations Committee.

The consolidated financial statements are audited and have been prepared using accounting policies in accordance with IFRS. The preparation of Management's Discussion and Analysis is based on the Company's financial results which have been prepared in accordance with IFRS. It compares the Company's financial performance in 2019 to 2018 and should be read in conjunction with the consolidated financial statements and accompanying notes.

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Management believes that the system of internal controls that have been designed and maintained at the Company provide reasonable assurance that financial records are reliable and form a proper basis for preparation of financial statements. The internal accounting control process includes Management's communication to employees of policies which govern ethical business conduct.

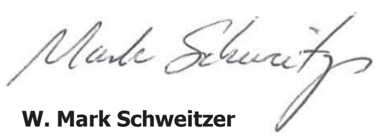
Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Board of Directors has appointed an Audit Committee consisting of unrelated, non-management directors which meets at least four times during the year with Management and independently with the external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the charter of the Audit Committee as set out in the Annual Information Form. The Audit Committee reviews the consolidated financial statements and Management's Discussion and Analysis before the consolidated financial statements are submitted to the Board of Directors for approval. The external auditors have free access to the Audit Committee without obtaining prior Management approval.

With respect to the external auditors, the Audit Committee approves the terms of engagement and reviews the annual audit plan, the Auditors' Report and results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The independent external auditors, KPMG LLP, have been appointed by the Board of Directors on behalf of the shareholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, financial performance and cash flows in accordance with IFRS. The report of KPMG LLP outlines the scope of their examination and their opinion on the consolidated financial statements.

Susan L. Riddell Rose
President & Chief Executive Officer



W. Mark Schweitzer
Vice President, Finance & Chief Financial Officer

March 18, 2020

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Perpetual Energy Inc.

Opinion

We have audited the consolidated financial statements of Perpetual Energy Inc. (the "Company"), which comprise:

- the consolidated statements of financial position as at December 31, 2019 and December 31, 2018
- the consolidated statements of loss and comprehensive loss for the years then ended
- the consolidated statements of changes in equity for the years then ended
- the consolidated statements of cash flows for the years then ended
- and notes to the consolidated financial statements, including a summary of significant accounting policies

Hereinafter referred to as the "financial statements".

In our opinion, the accompanying financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2019 and December 31, 2018, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the *"Auditors' Responsibilities for the Audit of the Financial Statements"* section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Material Uncertainty Related to Going Concern

We draw attention to note 1 in the financial statements, which indicates that there are upcoming maturities of the Company's reserve-based credit facility on November 30, 2020 and term loan on March 14, 2021. As stated in note 1 in the financial statements, these events or conditions, along with other matters as set forth in note 1 in the financial statements impacting the Company's ability to address these maturities, indicate that a material uncertainty exists that may cast significant doubt on the Company's ability to continue as a going concern.

Our opinion is not modified in respect of this matter.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditors' report thereon, included in a document likely to be entitled "2019 Annual Results".

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

The information, other than the financial statements and the auditors' report thereon, included in a document likely to be entitled "2019 Annual Results" is expected to be made available to us after the date of this auditors' report. If, based on the work we will perform on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact to those charged with governance.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.
- The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is Gregory Ronald Caldwell.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada

March 18, 2020

PERPETUAL ENERGY INC.
Consolidated Statements of Financial Position

As at (*Cdn$ thousands*)	December 31, 2019	December 31, 2018
Assets		
Current assets		
Accounts receivable (note 22)	**$ 5,056**	$ 8,931
Tourmaline Oil Corp. ("TOU") share investment (note 4)	**15,220**	28,132
Prepaid expenses and deposits	**1,154**	1,138
Fair value of derivatives (note 22)	**–**	7,012
	21,430	45,213
Fair value of derivatives (note 22)	**–**	3,906
Property, plant and equipment (note 5)	**194,634**	260,091
Exploration and evaluation (note 6)	**23,609**	25,879
Right-of-use assets (note 7)	**1,475**	–
Total assets	**$ 241,148**	$ 335,089
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 13,278**	$ 16,612
TOU share margin demand loan (note 9)	**100**	14,109
Revolving bank debt (note 10)	**47,552**	42,561
Senior notes (note 12)	**–**	14,536
Fair value of derivatives (note 22)	**10,542**	1,405
Gas over bitumen royalty financing (note 13)	**582**	680
Lease liabilities (note 14)	**633**	–
Provisions (note 15)	**2,382**	1,933
	75,069	91,836
Fair value of derivatives (note 22)	**2,732**	894
Term loan (note 11)	**44,274**	43,729
Senior notes (note 12)	**32,255**	17,344
Gas over bitumen royalty financing (note 13)	**289**	472
Lease liabilities (note 14)	**2,052**	–
Provisions (note 15)	**36,459**	39,431
Total liabilities	**193,130**	193,706
Equity		
Share capital (note 17)	**96,876**	1,338,369
Warrants (note 17c)	**923**	923
Contributed surplus	**44,234**	44,433
Deficit	**(94,015)**	(1,242,342)
Total equity	**48,018**	141,383
Total liabilities and equity	**$ 241,148**	$ 335,089

Future operations (note 1)
Contingencies (note 8)
Contractual obligations (note 16)

See accompanying notes to the consolidated financial statements.

Robert A. Maitland
Director

Geoffrey C. Merritt
Director

PERPETUAL ENERGY INC.
Consolidated Statements of Loss and Comprehensive Loss

For the year ended	December 31, 2019	December 31, 2018
(*Cdn$ thousands, except per share amounts*)		
Revenue		
Oil and natural gas (note 19)	**$ 74,361**	$ 86,128
Royalties	**(11,260)**	(10,594)
	63,101	75,534
Change in fair value of derivatives (note 22)	**(22,682)**	8,818
Gas over bitumen royalty credit	**852**	1,046
	41,271	85,398
Expenses		
Production and operating	**18,332**	19,229
Transportation	**6,258**	6,068
Exploration and evaluation (note 6)	**1,797**	2,212
General and administrative	**11,660**	13,630
Share-based payments (note 18)	**2,295**	2,573
Depletion and depreciation (note 5 and 7)	**31,188**	34,946
Loss on dispositions (note 5a)	**–**	223
Impairment (note 5b and 6)	**47,052**	7,200
Net loss from operating activities	**(77,311)**	(683)
Finance expense (note 20)	**(11,951)**	(10,122)
Change in fair value of TOU share investment (note 4)	**(3,207)**	(9,575)
Restructuring costs (note 15b)	**(1,546)**	–
Net loss and comprehensive loss	**(94,015)**	(20,380)
Loss per share (note 17d)		
Basic and diluted	**$ (1.56)**	$ (0.34)

See accompanying notes to the consolidated financial statements.

PERPETUAL ENERGY INC.
Consolidated Statements of Changes in Equity

(Cdn$ thousands, except share amounts)	Share capital (thousands)	Share capital ($thousands)	Warrants	Contributed surplus	Deficit	Total equity
Balance at December 31, 2018	60,240	$ 1,338,369	$ 923	$ 44,433	$ (1,242,342)	$ 141,383
Net loss	–	–	–	–	(94,015)	(94,015)
Common shares issued (note 17)	412	690	–	(690)	–	–
Change in shares held in trust (note 17)	(139)	159	–	(359)	–	(200)
Share-based payments (note 18)	–	–	–	850	–	850
Elimination of deficit (note 17)	–	(1,242,342)	–	–	1,242,342	–
Balance at December 31, 2019	**60,513**	**$ 96,876**	**$ 923**	**$ 44,234**	**$ (94,015)**	**$ 48,018**

(Cdn$ thousands, except share amounts)	Share capital (thousands)	Share capital ($thousands)	Warrants	Contributed surplus	Deficit	Total equity
Balance at December 31, 2017	59,263	$ 1,336,838	$ 923	$ 44,152	$ (1,221,962)	$ 159,951
Net loss	–	–	–	–	(20,380)	(20,380)
Common shares issued (note 17)	1,191	1,200	–	(1,192)	–	8
Change in shares held in trust (note 17)	(214)	331	–	(656)	–	(325)
Share-based payments (note 18)	–	–	–	2,129	–	2,129
Balance at December 31, 2018	**60,240**	**$1,338,369**	**$ 923**	**$ 44,433**	**$ (1,242,342)**	**$ 141,383**

See accompanying notes to the consolidated financial statements.

PERPETUAL ENERGY INC.
Consolidated Statements of Cash Flows

For the year ended	**December 31, 2019**	December 31, 2018
(*Cdn$ thousands*)		
Cash flows from (used in) operating activities		
Net loss	**$ (94,015)**	$ (20,380)
Adjustments to add (deduct) non-cash items:		
Depletion and depreciation (note 5 and 7)	**31,188**	34,946
Exploration and evaluation (note 6)	**1,599**	1,485
Share-based payments (note 18)	**406**	2,573
Unrealized change in fair value of derivatives (note 22)	**21,893**	(5,747)
Change in fair value of TOU share investment (note 4)	**3,207**	9,575
Loss on dispositions (note 5a)	**–**	223
Restructuring costs (note 15b)	**1,546**	–
Finance expense (note 20)	**2,671**	1,415
Impairment (note 5b and 6)	**47,052**	7,200
Decommissioning obligations settled (note 15a)	**(1,733)**	(1,969)
Payments of restructuring costs (note 15b)	**(610)**	(337)
Change in non-cash working capital (note 21)	**4,602**	2,541
Net cash flows from (used in) operating activities	**17,806**	31,525
Cash flows from (used in) financing activities		
Change in revolving bank debt, net of issue costs (note 10)	**4,792**	10,778
Change in TOU share margin demand loan, net of issue costs (note 9)	**(14,044)**	(4,425)
Change in senior notes, net of issue costs (note 12)	**(33)**	–
Payments of lease liabilities (note 14)	**(441)**	–
Payments of gas over bitumen royalty financing (note 13)	**(1,013)**	(1,135)
Common shares issued (note 17)	**–**	8
Shares purchased and held in trust (note 17)	**(200)**	(325)
Net cash flows from (used in) financing activities	**(10,939)**	4,901
Cash flows from (used in) investing activities		
Capital expenditures	**(12,939)**	(26,888)
Acquisitions (note 5 and note 6)	**–**	(1,871)
Net proceeds on dispositions (note 5a)	**–**	4,901
Proceeds on sale of TOU share investment (note 4)	**9,705**	278
Change in non-cash working capital (note 21)	**(3,633)**	(12,846)
Net cash flows from (used in) investing activities	**(6,867)**	(36,426)
Change in cash and cash equivalents	**–**	–
Cash and cash equivalents, beginning of year	**–**	–
Cash and cash equivalents, end of year	**$ –**	$ –

See accompanying notes to the 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 consolidated financial statements of the Company 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.

Future operations

Perpetual has a first lien, reserve-based credit facility (the "Credit Facility") (note 10). On December 24, 2019, Perpetual's syndicate of lenders completed their semi-annual borrowing base redetermination, reducing the Credit Facility borrowing limit (the "Borrowing Limit") from $55 million to $45 million effective January 22, 2020. In January 2020, the Company sold its remaining 1,000,000 TOU shares for net cash proceeds of $14.3 million (the "TOU Share Proceeds"). Net proceeds were used to repay the TOU share margin demand loan with the balance used to repay a portion of the Credit Facility. The next Borrowing Limit redetermination is scheduled on or prior to March 31, 2020. If the Credit Facility repayment term is not extended at the next redetermination, all outstanding advances will become payable on November 30, 2020. The extension of the Credit Facility repayment term is dependent on the Company's ability to repay or extend the term of the $45 million second lien term loan that matures and requires repayment on March 14, 2021 (note 11). The Company also has $33.6 million of unsecured senior notes that mature on January 23, 2022 (note 12).

Although the TOU Share Proceeds have reduced the Company's revolving bank debt borrowed under its Credit Facility, the Company remains dependent on the support of its lenders to the Credit Facility which has a current maturity of November 30, 2020. Further, the recent significant decline in natural gas and liquids prices has contributed to the Company projecting a significant reduction in cash flow from operating activities in 2020. The Company will require additional financing or will need to refinance the upcoming Credit Facility and term loan maturities as the available liquidity and operating cash flows are not anticipated to be sufficient. Perpetual is considering options including the sale or monetization of additional assets, the extension of existing debt maturity dates, or alternative financing.

However, due to the facts and circumstances detailed above, coupled with considerable economic instability and uncertainty in the oil and gas markets which negatively impacts operating cash flows and lender and investor sentiment, there remains considerable risk around the Company's ability to address its liquidity shortfalls and upcoming maturities. In addition, there continues to be some uncertainty regarding the Statement of Claim (note 8) which may restrict management's ability to manage its capital structure. As a result, there is a material uncertainty surrounding the Company's ability to continue as a going concern that creates significant doubt as to the ability of the Company to meets its obligations as they come due and, therefore, it may be unable to realize its assets and discharge its liabilities in the normal course of business.

These financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Corporation will be able to realize its assets and discharge its liabilities in the normal course of business. These financial statements do not reflect adjustments that would be necessary if the going concern assumption were not appropriate. If the going concern basis were not appropriate for these financial statements, then adjustments would be necessary in the carrying value of the assets and liabilities, the reported revenues and expenses, and the balance sheet classifications used. These adjustments could be material.

2. BASIS OF PREPARATION

These consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The consolidated financial statements of the Company were approved and authorized for issue by the Board of Directors on March 18, 2020.

These financial statements have been prepared in accordance with generally accepted accounting principles applicable to a going concern, which assumes that the Company will be able to realize its assets and discharge its liabilities in the normal course of business. They have been prepared on a historical cost basis except for the TOU share investment (note 4), gas over bitumen royalty financing (note 13) and derivative financial instruments (note 22) that have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company and its subsidiaries.

a) Critical accounting judgments and significant estimates

The preparation of the consolidated financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenue and expenses. These judgments, estimates, and assumptions are continuously evaluated and are based on management's experience and all relevant information available to the Company at the time of financial statement preparation. As the effect of future events cannot be determined with certainty, the actual results may differ from estimates. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future periods affected.

Information about the critical judgments and significant estimates made by management are described below and in the relevant notes to the financial statements.

b) Critical accounting judgments:

The following are the critical judgments that management has made in the process of applying the Company's accounting policies. These judgments have the most significant effect on the amounts reported in the consolidated financial statements.

i) Cash-generating units ("CGUs")

The Company allocates its oil and natural gas properties to CGUs, identified as the smallest group of assets that generate cash inflows independent of the cash inflows of other assets or groups of assets. Determination of the CGUs is subject to management's judgement and is based on geographical proximity, shared infrastructure, and similar exposure to market risk.

ii) Identification of impairment indicators

Judgment is required to assess when indicators of impairment or reversals exist and whether calculation of the recoverable amount of an asset is necessary. Management considers internal and external sources of information including oil and natural gas prices, expected production volumes, anticipated recoverable quantities of proved and probable reserves and rates used to discount future cash flow estimates. Judgement is required to assess these factors when determining if the carrying amount of an asset is impaired, or in the case of a previously impaired asset, whether the carrying amount of the asset has been restored.

iii) Componentization

For the purposes of depletion, the Company allocates its oil and natural assets to components with similar useful lives and depletion methods. The grouping of assets is subject to management's judgment and is performed on the basis of geographical proximity and similar reserve life. The Company's oil and gas assets are depleted on a unit-of-production basis.

iv) Exploration and evaluation expenditures

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as exploration and evaluation ("E&E") assets pending determination of technical feasibility and commercial viability. Establishment of technical feasibility and commercial viability is subject to judgment and involves management's review of project economics, resource quantities, expected production techniques, production costs and required capital expenditures to develop and extract the underlying resources. Management uses the establishment of commercial reserves within the exploration area as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets attributable to those reserves are tested for impairment and reclassified from E&E assets to a separate category within property, plant and equipment referred to as oil and natural gas properties.

v) Joint arrangements

Judgment is required to determine when the Company has joint control over an arrangement. In establishing joint control, the Company considers whether unanimous consent is required to direct the activities that significantly affect the returns of the arrangement, such as the capital and operating activities of the arrangement.

Once joint control has been established, judgment is also required to classify a joint arrangement. The type of joint arrangement is determined through analysis of the rights and obligations arising from the arrangement by considering its structure, legal form, and terms agreed upon by the parties sharing control. An arrangement where the controlling parties have rights to the assets and revenues, and obligations for the liabilities and expenses, is classified as a joint operation. Arrangements where the controlling parties have rights to the net assets of the arrangement are classified as joint ventures.

vi) Deferred taxes

Deferred tax assets (if any) are recognized only to the extent it is considered probable that those assets will be recoverable. This involves an assessment of when those deferred tax assets are likely to reverse and judgment as to whether there will be sufficient taxable profits available to offset the tax assets when they do reverse. This requires assumptions regarding future profitability and is therefore inherently uncertain. To the extent assumptions regarding future profitability change, there can be an increase or decrease in the amounts recognized in respect of deferred tax assets as well as the amounts recognized in profit or loss in the period in which the change occurs.

vii) Revenue – principal versus agent

When determining if the Company acted as a principal or as an agent in transactions, management determines if the Company obtains control of the product. As part of this assessment, management considered if the Company obtained control of the goods or services more than momentarily, in advance of transferring those goods or services to the customer. In this assessment, the Company considered indicators that it controlled the goods or services, including whether the Company was primarily responsible for the goods and services, whether the Company had inventory risk and whether the Company had discretion in establishing prices for the goods or services. Where control was indicated, the Company has been determined to be the principal. In other cases, the Company has been determined to be the agent.

c) Significant estimates:

The following assumptions represent the key sources of estimation uncertainty at the end of the reporting period. As future confirming events occur, the actual results may differ from estimated amounts.

i) Reserves

The Company uses estimates of natural gas, oil, and natural gas liquids ("NGL" or "liquids") reserves in the calculation of depletion and also for value in use ("VIU") and fair value less costs of disposal ("FVLCD") calculations of non-financial assets. Estimates of economically recoverable natural gas, oil, and NGL reserves and their future net cash flows are based upon a number of variable factors and assumptions, such as geological, geophysical, and engineering assessments of hydrocarbons in place on the Company's lands, historical production from the properties, production rates, future commodity prices, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by government agencies and future operating costs. The geological, economic and technical factors used to estimate reserves may change from period to period. Changes in the reported reserves could have a material impact on the carrying values of the Company's oil and natural gas properties, the calculation of depletion and depreciation and the timing of decommissioning expenditures.

Reserve engineers are engaged at least annually to independently evaluate or review the recoverable quantities and estimated future cash flows from the Company's interest in oil and natural gas properties. This evaluation of proved and proved plus probable reserves is prepared in accordance with the reserve definitions contained in National Instrument 51-101 and the COGE Handbook.

ii) Provisions for decommissioning obligations

Decommissioning, abandonment, and site reclamation expenditures for production facilities, wells, and pipelines are expected to be incurred by the Company over many years into the future. Amounts recorded for decommissioning obligations and the associated accretion are calculated based on estimates of the extent and timing of decommissioning activities, future site remediation regulations and technologies, inflation, liability specific discount rates and related cash flows. The provision represents management's best estimate of the present value of the future abandonment and reclamation costs required. Actual abandonment and reclamation costs could be materially different from estimated amounts.

iii) Derivative financial instruments

Derivatives are measured at fair value on each reporting date. Fair value is the price that would be received or paid to exit the position as of the measurement date. The Company uses estimated external forward market price curves available at period end and the contracted volumes over the contracted term to determine the fair value of each contract. Changes in market pricing between period end and settlement of the derivative contracts could have a material impact on financial results related to the derivatives.

iv) Gas over bitumen royalty financing

The gas over bitumen royalty financing is measured at fair value on each reporting date. Fair value is the price that would be paid to exit the position as of the measurement date.

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 remaining contracted deemed volume. Changes in market pricing between period end and settlement could have a material impact on financial results related to the gas over bitumen royalty financing.

v) Share-based payments

Share options, deferred share options, and long term incentive awards issued by the Company are recorded at fair value using the Black Scholes option pricing model. In assessing the fair value of share options and deferred share options, estimates have to be made regarding the expected volatility in share price, option life, dividend yield, risk-free rate and estimated forfeitures at the initial grant date.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently to all periods presented in these annual consolidated financial statements and have been applied consistently by the Company and its subsidiaries, with the exception of IFRS 16 "Leases" noted below.

a) Basis of consolidation

i) Subsidiaries

Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies of an entity so as to obtain benefits from its activities. In assessing control, potential voting rights that are currently exercisable are considered. The financial statements of subsidiaries are included in the consolidated financial statements from the date that control commences until the date that control ceases.

ii) Business combinations

The acquisition method of accounting is used to account for acquisitions of subsidiaries and assets that meet the definition of a business under IFRS. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued, and liabilities incurred or assumed at the date of acquisition of control. Identifiable assets acquired, and liabilities assumed in a business combination are measured at their recognized amounts (generally fair value) at the acquisition date. The excess of the cost of acquisition over the recognized amounts of the identifiable assets acquired and liabilities assumed is recorded as goodwill. If the cost of acquisition is less than the recognized amount of the net assets acquired, the difference is recognized as a bargain purchase gain in net loss.

iii) Jointly owned assets

Many of the Company's oil and natural gas activities involve jointly owned assets which are not conducted through a separate entity. The consolidated financial statements include the Company's proportionate share of these jointly owned assets, liabilities, revenues and expenses.

iv) Transactions eliminated on consolidation

Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the consolidated financial statements.

b) Accounting pronouncements adopted

IFRS 16 "Leases"

Effective January 1, 2019, the Company adopted IFRS 16, "Leases", which replaced IAS 17, "Leases" and IFRIC 4, "Determining Whether an Arrangement Contains a Lease". The Company applied the new standard using the modified retrospective approach and, in accordance with the transitional provisions, the comparative information has not been restated.

i) Right-of-use assets (note 7)

The Company recognizes right-of-use assets and lease liabilities at the lease commencement date. The assets are initially measured at cost, which comprises the initial amount of the lease liabilities adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

The right-of-use assets are depreciated to the earlier of the end of the useful life of the asset or the lease term using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. Perpetual presents right-of-use assets as its own line item on the consolidated statement of financial position. The lease term includes periods covered by an option to extend if the Company is reasonably certain to exercise that option. In addition, the right-of-use assets are periodically reduced by impairment losses, if any, and adjusted for certain remeasurements of the lease liabilities. The depreciation term of the right-of-use assets is between 2 and 5 years.

ii) Lease liabilities (note 14)

The lease liabilities are initially measured at the present value of the future lease payments, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate.

The lease liabilities are measured at amortised cost using the effective interest rate method. They are remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liabilities are remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use assets, or is recorded in profit or loss if the carrying amount of the right-of-use assets has been reduced to zero. Lease payments are applied against the lease liabilities, with a portion allocated as cash finance expense using the effective interest rate method. Perpetual presents lease liabilities as their own line item on the consolidated statement of financial position.

iii) Critical accounting judgements and estimate uncertainty

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of the right-of-use assets and lease liabilities, and the resulting interest and depreciation expense. Actual results could differ significantly as a result of these estimates. Key areas where management has made judgments, estimates, and assumptions related to the application of IFRS 16 include:

- *Incremental borrowing rate*: The rates used to present value future lease payments are based on judgments about the economic environment in which the Company operates and theoretical analyses about the security provided by the underlying leased asset, the amount of funds required to be borrowed in order to meet the future lease payments associated with the leased asset, and the term for which these funds would be borrowed; and
- *Lease term*: In determining the period which the Company has the right to use an underlying asset, management considers the non-cancellable period along with all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option.

iv) Transition impact

Perpetual has elected to use the modified retrospective approach upon adoption and therefore, the comparative information has not been restated. The effect of initially applying the standard was a $3.1 million increase to right-of-use assets and lease liabilities, with no impact on deficit. The previously recorded lease inducement recognized under IAS 37 was incorporated into the recorded lease liabilities. As this lease inducement represented a liability over fair market value of the head office lease, the right-of-use asset was correspondingly reduced by the same amount ($1.3 million). The weighted average incremental borrowing rate used to determine the right-of-use assets and lease liabilities on adoption was approximately 6.4%. Leases recognized under IFRS 16 largely relate to the Company's head office lease in Calgary.

Upon transition, the Company used the following practical expedients when applying IFRS 16 to leases previously classified as operating leases under IAS 17:

- right-of-use assets and lease liabilities for leases with less than 12 months of lease term were not recognized;
- right-of-use assets and lease liabilities for leases of low-value assets were not recognized;
- applied a single discount rate to a portfolio of leases with similar characteristics;
- excluded initial direct costs from measuring right-of-use assets at the date of initial application; and
- adjusted the right-of-use assets by the amount of an IAS 37 lease inducement provision immediately before the date of initial application, as an alternative to an impairment review.

The following table provides a reconciliation of the lease commitments disclosed as at December 31, 2018 to the Company's lease liabilities as at January 1, 2019:

	Total
Lease commitments	
Office leases	6,489
Vehicle leases	220
Other leases	133
Lease commitments, December 31, 2018	**6,842**
Non-lease components and variable payments	(4,310)
Lease inducement recognized under IAS 37 (note 15b)	1,267
	3,799
Impact of discounting	(673)
Lease liabilities recognized, January 1, 2019 (note 14)	**3,126**

The adoption of IFRS 16 had the following impact on the Company's financial results for the year ended December 31, 2019, compared to what would have occurred had the new accounting policy not been adopted:

(*$ thousands*)	**Decrease (increase) in net loss**	**Impact on net cash flows from (used in) operating activities**	**Impact on net cash flows from (used in) financing activities**
Production and operating expense	93	93	–
General and administrative expense	335	335	–
Depletion and depreciation expense	(384)	–	–
Cash interest on lease liabilities	(189)	(189)	–
Payments of lease liabilities	–	–	(441)
Net IFRS 16 implementation impact	**(145)**	**239**	**(441)**

c) Financial instruments

Financial instruments comprise accounts receivable, TOU share investment, fair value of derivative assets and liabilities, TOU share margin demand loan, accounts payable and accrued liabilities, revolving bank debt, term loan, gas over bitumen royalty financing, and senior notes. These financial instruments are recognized initially at fair value, net of any directly attributable transaction costs.

i) Classification and measurement of financial assets

A financial asset is measured at amortized cost if it meets both of the following conditions and is not designated at fair value through profit or loss ("FVTPL"):

- it is held within a business model whose objective is to hold assets to collect contractual cash flows; and
- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

A debt investment is measured at fair value through other comprehensive income ("FVOCI") if it meets both of the following conditions and is not designated at FVTPL:

- it is held within a business model whose objective is achieved by both collecting contractual cash flows and selling financial assets; and

- its contractual terms give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding.

On initial recognition of an equity investment that is not held for trading, the Company may irrevocably elect to present subsequent changes in the investment's fair value in other comprehensive income ("OCI"). This election is made on an investment-by-investment basis.

All financial assets not classified as measured at amortized cost or FVOCI as described above are measured at FVTPL. On initial recognition, the Company may irrevocably designate a financial asset that otherwise meets the requirements to be measured at amortized cost or at FVOCI at FVTPL if doing so eliminates or significantly reduces an accounting mismatch that would otherwise arise.

A financial asset (unless it is a trade receivable without a significant financing component that is initially measured at the transaction price) is initially measured at fair value plus, for an item not at FVTPL, transaction costs that are directly attributable to its acquisition.

The following accounting policies apply to the subsequent measurement of financial assets:

a) Financial assets at FVTPL

These assets are subsequently measured at fair value. Net gains and losses, including any interest or dividend income, are recognized in profit or loss.

b) Financial assets at amortized cost

These assets are subsequently measured at amortized cost using the effective interest method. The amortized cost is reduced by impairment losses. Interest income, foreign exchange gains and losses and impairment are recognized in profit or loss. Any gain or loss on derecognition is recognized in profit or loss.

c) Debt investments at FVOCI

These assets are subsequently measured at fair value. Interest income calculated using the effective interest method, foreign exchange gains and losses and impairment are recognized in profit or loss. Other net gains and losses are recognized in OCI. On derecognition, gains and losses accumulated in OCI are reclassified to profit or loss.

ii) Classification and measurement of financial liabilities

Financial liabilities are classified and measured at amortized cost or FVTPL. A financial liability is classified at FVTPL if it is a derivative or it is designated as such on initial recognition. Financial liabilities at FVTPL are measured at fair value and net gains and losses, including any interest expense, are recognized in profit or loss. Other financial liabilities are subsequently measured at amortized cost using the effective interest method. Interest expense and foreign exchange gains and losses are recognized in profit or loss. Any gain or loss on derecognition is also recognized in profit or loss.

The Company has classified accounts receivable, TOU share margin demand loan, accounts payable and accrued liabilities, revolving bank debt, term loan and senior notes as amortized cost. The TOU share investment and gas over bitumen royalty financing have been classified as FVTPL.

iii) Derivative assets and liabilities

The Company has entered into certain financial derivative contracts to manage the exposure to market risks from fluctuations in commodity prices and currency rates. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers all commodity and currency contracts to be economic hedges. As a result, all financial derivative contracts are designated as FVTPL and recorded as derivatives on the statement of financial position at fair value. Changes in the fair value of the commodity price and currency rate derivatives are recognized in net loss.

The Company has accounted for its forward physical delivery fixed-price sales contracts as derivative financial instruments. Accordingly, such forward physical delivery fixed-price sales contracts are designated as FVTPL and recorded as derivatives on the statement of financial position at fair value.

Transaction costs on derivatives are recognized in net loss when incurred.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in net loss.

iv) Share capital and warrants

Incremental costs directly attributable to the issue of common shares, warrants and share options are recognized as a deduction from equity, net of any tax effects.

d) Property, plant and equipment

i) Production and development costs

Items of property, plant and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The initial cost of property, plant and equipment includes the purchase price or construction costs, costs that are directly attributable to bringing the asset into commercial operations, the initial estimate of decommissioning costs, and borrowing costs for qualifying assets.

Significant parts of an item of property, plant and equipment, including oil and natural gas properties, that have different useful lives from the life of the area or facility in general, are accounted for as separate items.

Gains and losses on disposition of an item of property, plant and equipment, including oil and natural gas properties, are determined by comparing the proceeds from disposition with the carrying amount of property, plant and equipment and are recognized in net loss. The carrying amount of any replaced or disposed item of property, plant and equipment is derecognized.

ii) Subsequent costs

Costs incurred after the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant and equipment are recognized as property, plant and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized property, plant and equipment generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves, and are accumulated on a field or geotechnical area basis. All other expenditures including the costs of the day-to-day servicing of property, plant and equipment are recognized as production and operating expense in net loss as incurred.

iii) Depletion and depreciation

The net carrying amount of development or production assets is depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable reserves, considering estimated future development costs necessary to bring those reserves into production and future decommissioning costs. The future development cost estimates are reviewed by independent reserve engineers at least annually.

Costs associated with office furniture, information technology, and leasehold improvements are carried at cost and are depreciated on a straight-line basis over a period ranging from one to three years.

Depreciation methods, useful lives and residual values are reviewed at each period end date for all classes of property, plant, and equipment.

e) Exploration and evaluation ("E&E") expenditures

Pre-license costs, geological and geophysical costs and lease rentals of undeveloped properties are recognized in net loss as incurred.

E&E costs, consisting of the costs of acquiring oil and natural gas licenses, are capitalized initially as E&E assets according to the nature of the assets acquired. Costs associated with drilling exploratory wells in an undeveloped area are capitalized as E&E costs. The costs are accumulated in cost centers by well, field or exploration area pending determination of technical feasibility and commercial viability. When technical feasibility and commercial viability are determined, the relevant expenditure is transferred to property, plant and equipment as oil and natural gas properties, after impairment is assessed and any applicable impairment loss is recognized in net loss.

The Company's E&E assets consist of undeveloped land, exploratory drilling assets, and bitumen evaluation assets. Gains and losses on disposition of E&E assets are determined by comparing the proceeds from disposition with the carrying amount and are recognized in net loss.

f) Assets held for sale

Non-current assets, or disposal groups consisting of assets and liabilities ("disposal groups"), are classified as held for sale if their carrying amounts will be recovered principally through a sale transaction rather than through continuing use. Assets and liabilities qualifying as held for sale must be available for immediate sale in their present condition subject to normal terms and conditions, and their sale must be highly probable.

Non-current assets, or disposal groups, are measured at the lower of the carrying amount and FVLCD, with impairments recognized in net loss. Non-current assets or disposal groups held for sale are presented in current assets and liabilities within the statement of financial position. Assets held for sale are not subject to depletion and depreciation.

g) Impairment

i) Financial assets

The Company has elected to measure loss allowances for trade receivables and contract assets at an amount equal to lifetime expected credit losses ("ECLs"). The maximum period considered when estimating ECLs is the maximum contractual period over which the Company is exposed to credit risk.

ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e. the difference between the cash flows due to the entity in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the financial asset.

Loss allowances for financial assets are deducted from the gross carrying amount of the assets. Impairment losses on financial assets are presented under "other expenses" in the statement of loss and comprehensive loss.

ii) Non-financial assets

The carrying amounts of the Company's non-financial assets, other than E&E assets, are reviewed at each period end date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. E&E assets are assessed for impairment when they are reclassified to property, plant and equipment, as oil and natural gas properties, and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together at a CGU level. The recoverable amount of an asset or a CGU is determined based on the higher of its FVLCD and its VIU. FVLCD is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCD of oil and gas properties is generally determined as the net present value of estimated future cash flows expected to arise from the continued use of the CGU and its eventual disposition, using assumptions that an independent market participant may take into account. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU. In determining VIU, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset. VIU is generally determined by reference to the present value of the future cash flows expected to be derived from production of proved and probable reserves.

E&E assets are assessed for impairment both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to oil and natural gas properties in property, plant and equipment. If a test is required as a result of triggering facts and circumstances, the Company considers whether the combined recoverable amount of oil and natural gas properties and E&E assets at the total company level is sufficient to cover the combined carrying value of E&E and oil and natural gas assets.

An impairment is recognized if the carrying value of a CGU exceeds the recoverable amount for that CGU. The Company determines the recoverable amount by using the greater of FVLCD and the VIU. VIU is generally the future cash flows expected to be derived from production of proved and probable reserves estimated by the Company's third-party reserve evaluators. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amount of assets in the unit (group of units) on a pro rata basis. Impairment losses are recognized in net income or loss.

In respect of other assets, impairment losses recognized in prior years are assessed at each period end date for any indication that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

h) Share-based payments

Fixed equity awards granted under the equity-settled share-based payment plans and agreements are measured at grant-date fair value. Fair values are determined by means of an option pricing model using the exercise price of the equity instrument granted, the share price at the grant date, the expected life of the grant based on the vesting date and expiry date, estimates of share price volatility, and interest rates over the expected contractual life of the equity award. A forfeiture rate is estimated on the grant date and is subsequently adjusted to reflect the actual number of options that vest.

The costs of the equity-settled share-based payments are recognized within general and administrative expense, production and operating expense or property, plant and equipment to the extent they are directly attributable, with a corresponding increase in contributed surplus over the vesting period. Upon exercise or settlement of an equity-based instrument, consideration received, and associated amounts previously recorded in contributed surplus are recorded to share capital.

Certain awards granted under the performance share rights plan may be settled in cash, in common shares of the Company, or a combination thereof at the discretion of the Company's Board of Directors. Fixed value, equity-settled awards are accounted for as cash-settled share-based payment transactions and are expensed into profit and loss over the unit vesting period with an associated accumulation in liabilities, as a variable number of equity units will be required to settle the liability.

i) Shares held in trust

The Company has share-based payment plans whereby employees may be entitled to receive shares of the Company purchased on the open market by a trustee controlled by the Company. Shares acquired and held by the trustee for the benefit of employees that have not yet been issued to employees, are a separate category of equity that are presented net of common shares outstanding in share capital on the statement of financial position (note 17b). The balance of shares held in trust represents the cumulative cost of shares held by the trustee. Upon the issuance of shares to the employee, the amount attributable to an employee is deducted from the balance of shares held in trust and removed from contributed surplus.

j) Provisions

Provisions are recognized when the Company has a current legal or constructive obligation as a result of a past event, which can be reliably estimated, and will require the outflow of economic resources to settle the obligation. A non-current provision is determined using the estimated future cash flows discounted at a rate that reflects current market conditions and liability specific risks.

i) Decommissioning obligations

The Company's activities give rise to dismantling, decommissioning, and site disturbance remediation activities. A provision is recorded for the estimated cost of site restoration and capitalized in the relevant asset category.

Decommissioning obligations are measured at the present value of management's estimate of the extent and timing of expenditures required to settle the obligation at the statement of financial position date, using a risk-free interest rate not adjusted for credit risk. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the timing and estimate of future cash flows underlying the obligation, and changes in the risk-free rate. The accretion of the provision due to the passage of time is recognized in net loss whereas changes in the provision arising from changes in estimated cash flows or changes in the risk-free rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

ii) Restructuring provisions

Restructuring provisions are recognized when the Company has developed a detailed formal plan for restructuring and has announced the plan's main features to those affected by it. The measurement of a restructuring provision includes only the direct expenditures arising from the restructuring, which are those amounts that are not associated with the ongoing activities of the Company.

A provision for employee downsizing costs is recognized when the Company has announced the restructuring plan to those affected by it, and can no longer withdraw the offer of those benefits. The provision is measured on initial recognition at the Company's best estimate of the expenditure required to settle the obligation.

k) Revenue

Revenue from the sale of crude oil, natural gas and NGL 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.

The Company's entitlement to gas over bitumen royalty adjustments under the Natural Gas Royalty Regulation (2004) with respect to foregone production (deemed production) from natural gas wells shut-in for the benefit of bitumen producers in the Athabasca oil sands area, is recognized as gas over bitumen royalty credit revenue in the period that deemed production occurs, to the extent that the revenue is expected to be recovered through gas Crown royalties otherwise payable.

l) Income tax

Income tax expense comprises current and deferred components. Income tax expense is recognized in net loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the period end date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the period end date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each period end date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

m) Loss per share amounts

Basic income or loss per share is calculated by dividing the net loss by the weighted average number of common shares outstanding during the period. For the dilutive net income per share calculation, the weighted average number of shares outstanding is adjusted for the potential number of shares which may have a dilutive effect on net income.

Diluted income per share is calculated giving effect to the potential dilution that would occur if outstanding warrants, share options, restricted rights, performance share units, or deferred compensation awards were exercised or converted into common shares. The weighted average number of diluted shares is calculated in accordance with the treasury stock method for warrants, share options, restricted rights, deferred shares, deferred options, and performance share units. The treasury stock method assumes that the proceeds received from the exercise of all potentially dilutive instruments are used to repurchase common shares at the average market price.

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

	December 31, 2019		December 31, 2018	
	Shares *(thousands)*	**Amount *($thousands)***	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of year	**1,656**	**$ 28,132**	1,667	$ 37,985
Sold	**(656)**	**(9,705)**	(11)	(278)
Unrealized change in fair value	**–**	**(3,207)**	–	(9,575)
Balance, end of year	**1,000**	**$ 15,220**	1,656	$ 28,132

TOU is engaged in the acquisition, exploration, development and production of oil and natural gas properties situated in western Canada. TOU shares are listed on the Toronto Stock Exchange under the trading symbol "TOU".

In December of 2019, the Company sold 656,773 TOU shares at a weighted average price of $14.78 per share, for net cash proceeds of $9.7 million. Proceeds from the sale of TOU shares were used to pay down the balance of the TOU share margin demand loan by $9.1 million. The remaining proceeds were used to repay Credit Facility borrowings.

At December 31, 2019, the Company held 1.0 million (December 31, 2018 – 1.66 million) TOU shares with a fair market value of $15.2 million (December 31, 2018 – $28.1 million) based on a December 31, 2019 closing price of $15.22 per share (December 31, 2018 – $16.98) and were pledged as security for the TOU share margin demand loan (note 9). Net loss for the year ended December 31, 2019 includes an unrealized loss of $3.2 million (2018 – unrealized loss of $9.6 million) representing the change in fair value of TOU shares held during the year.

Subsequent to December 31, 2019, the Company sold the remaining 1,000,000 TOU shares at a weighted average price of $14.32 per share for net cash proceeds of $14.3 million. Proceeds were used to repay the $0.1 million TOU share margin demand loan in full (note 9) and to pay down a portion of the revolving bank debt (note 10).

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

	Oil and Gas Properties	Corporate Assets	Total
Cost			
December 31, 2017	$ 687,301	$ 7,261	$ 694,562
Additions	26,073	353	26,426
Acquisitions	1,261	–	1,261
Change in decommissioning obligations related to PP&E (note 15a)	4,644	–	4,644
Transfers from exploration and evaluation (note 6)	770	–	770
Dispositions	(848)	–	(848)
December 31, 2018	$ 719,201	$ 7,614	$ 726,815
Additions	12,201	74	12,275
Change in decommissioning obligations related to PP&E (note 15a)	(1,211)	–	(1,211)
Transfers from exploration and evaluation (note 6)	1,335	–	1,335
December 31, 2019	**$ 731,526**	**$ 7,688**	**$ 739,214**
Accumulated depletion, depreciation and impairment			
December 31, 2017	$ (424,665)	$ (7,113)	$ (431,778)
Depletion and depreciation	(34,804)	(142)	(34,946)
December 31, 2018	$ (459,469)	$ (7,255)	$ (466,724)
Depletion and depreciation	(30,628)	(176)	(30,804)
Impairment (note 5b)	(47,052)	–	(47,052)
December 31, 2019	**$ (537,149)**	**$ (7,431)**	**$ (544,580)**
Carrying amount			
December 31, 2018	$ 259,732	$ 359	$ 260,091
December 31, 2019	**$ 194,377**	**$ 257**	**$ 194,634**

At December 31, 2019, property, plant and equipment included $1.9 million (December 31, 2018 – $1.9 million) of costs currently not subject to depletion.

For the year ended December 31, 2019, $0.4 million (December 31, 2018 – $0.7 million) of direct general and administrative expenses were capitalized. Future development costs for the year ended December 31, 2019 of $358.8 million (December 31, 2018 – $346.0 million) were included in the depletion calculation.

a) Dispositions

Proceeds (payments) on dispositions

	December 31, 2019	December 31, 2018
Proceeds on dispositions of oil and gas properties	**$ –**	$ 13,441
Payments on retained shallow gas marketing arrangements	**–**	(8,540)
Net proceeds on dispositions	**$ –**	$ 4,901

Gain (loss) on dispositions

	December 31, 2019	December 31, 2018
Proceeds on dispositions of oil and gas properties	**$ –**	$ 13,441
Carrying amount of PP&E disposed (note 5)	**–**	(848)
Carrying amount of E&E disposed (note 6)	**–**	(12,442)
Carrying amount of decommissioning obligations disposed (note 15a)	**–**	500
Gain on disposition of oil and gas properties	**–**	651
Realized loss on retained shallow gas marketing arrangements	**–**	(874)
Loss on dispositions	**$ –**	$ (223)

Dispositions during the year ended December 31, 2018 included the sale of non-core royalty interests and exploration and evaluation properties for gross proceeds of $13.4 million, resulting in a net gain on oil and gas properties of $0.7 million. Included in the gain was $0.5 million in decommissioning obligations associated with the non-core properties that were sold. There were no dispositions in 2019.

b) Impairment of cash-generating units

During the fourth quarter of 2019, the Company decommissioned its Panny natural gas properties due to an excessive property tax burden and determined that the associated $0.7 million carrying value was no longer recoverable. Accordingly, a $0.7 million impairment charge was included in net loss.

For the quarter ended December 31, 2019, the Company conducted an assessment of impairment indicators for the Company's CGUs. In performing the review, management determined that the considerable economic instability and uncertainty in the oil and natural gas markets which negatively impacts operating cash flows, coupled with the Company's available liquidity at December 31, 2019, justified calculation of the recoverable amount of the liquids-rich natural gas assets which comprise the West Central CGU. The recoverable amount of the West Central CGU was determined using value-in-use ("VIU") based on the net present value of cash flows from oil, natural gas, and NGL reserves using estimates of total proved plus probable reserves evaluated or reviewed by the Company's independent reserves evaluators, along with commodity price estimates based on an average of three independent reserve evaluators, and an estimate of market discount rates between 10% and 22% to consider risks specific to the asset.

At December 31, 2019, the Company determined that the carrying amount of the West Central CGU exceeded the recoverable amount of $130.8 million and accordingly, an impairment charge of $23.8 million was included in net loss.

Commodity price estimates based on an average of three independent reserve evaluators were used in the VIU calculations as at December 31, 2019:

Year	WTI Crude Oil *(US$/bbl)*	USD/CDN exchange rate *(US$/Cdn$)*	Alberta Heavy Crude Oil *(Cdn$/bbl)*	AECO Gas *(Cdn$/MMBtu)*
2020	61.00	0.760	51.23	2.04
2021	63.75	0.770	56.11	2.32
2022	66.18	0.785	57.72	2.62
2023	67.91	0.785	59.45	2.71
2024	69.48	0.785	61.09	2.81
2025	71.07	0.785	62.75	2.89
2026	72.68	0.785	64.43	2.96
2027	74.24	0.785	66.04	3.03
2028	75.73	0.785	67.55	3.09
2029	77.24	0.785	69.08	3.16
2030	78.79	0.785	70.46	3.23
2031	80.36	0.785	71.87	3.29
2032	81.97	0.785	73.31	3.36
2033	83.61	0.785	74.78	3.43
2034(1)	85.28	0.785	76.27	3.49

(1) Commodity price estimates escalate 2.0% per year thereafter.

As at December 31, 2019, if discount rates used in the calculation of impairment changed by 1% with all other variables held constant, the impairment loss for the period would change by approximately $7.0 million. As at December 31, 2019, if commodity price estimates changed by 5% with all other variables held constant, the impairment loss for the period would change by approximately $19.0 million.

For the quarter ended June 30, 2019, the Company conducted an assessment of impairment indicators for the Company's CGUs. In performing the review, management determined that the decrease in natural gas prices in the forward market justified calculation of the recoverable amount of the liquids-rich natural gas assets which comprise the West Central CGU. The recoverable amount of the West Central CGU was determined using VIU based on the net present value of cash flows from oil, natural gas, and NGL reserves using estimates of total proved plus probable reserves evaluated or reviewed by the Company's independent reserves evaluators, along with commodity price estimates based on an average of three independent reserve evaluators, and an estimate of market discount rates between 10% and 20% to consider risks specific to the asset.

At June 30, 2019, the Company determined that the carrying amount of the West Central CGU exceeded the recoverable amount of $165.0 million and accordingly, an impairment charge of $22.6 million was included in net loss.

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

	December 31, 2019	December 31, 2018
Balance, beginning of year	**$ 25,879**	$ 46,704
Additions	**664**	462
Acquisitions	**–**	610
Dispositions	**–**	(12,442)
Impairments	**–**	(7,200)
Non-cash exploration and evaluation expense	**(1,599)**	(1,485)
Transfers to property, plant and equipment	**(1,335)**	(770)
Balance, end of year	**$ 23,609**	$ 25,879

During the year ended December 31, 2019, $0.2 million (2018 – $0.7 million) in costs were charged directly to E&E expense in 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 properties 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 net 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 on E&E assets. 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 on undeveloped land sold to maintain exposure to future drilling conducted by the purchaser.

7. RIGHT-OF-USE ASSETS

The Company leases several assets including office space, vehicles, and miscellaneous other assets. Information about leases for which the Company is a lessee is presented below:

	Head office	Vehicles	Other leases	Total
Cost				
January 1, 2019	$ 1,498	$ 200	$ 161	$ 1,859
Additions	–	–	–	–
December 31, 2019	**$ 1,498**	**$ 200**	**$ 161**	**$ 1,859**
Accumulated depreciation				
January 1, 2019	$ –	$ –	$ –	$ –
Depreciation	(240)	(80)	(64)	(384)
December 31, 2019	**$ (240)**	**$ (80)**	**$ (64)**	**$ (384)**
Carrying amount				
January 1, 2019	$ 1,498	$ 200	$ 161	$ 1,859
December 31, 2019	**$ 1,258**	**$ 120**	**$ 97**	**$ 1,475**

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

Perpetual's Application for Summary Dismissal was heard during the fourth quarter of 2018. On August 15, 2019 the Court issued its oral decision and on January 13, 2020 the Court issued its written decision which dismissed and struck all but one of the claims filed by PwC against Perpetual. Consistent with the position advanced from the outset by the Company, the Court ruled in favour of Perpetual and struck PwC's oppression claim and claim for relief on the grounds of public policy, statutory illegality and equitable rescission.

Despite referring several times to this transaction as one of "arm's length" in the decision, the Court did not find that the test for summary dismissal relating to whether the transaction was an arm's length transfer for purposes of section 96(1) of the Bankruptcy and Insolvency Act (the "BIA") was met, on the balance of probabilities. Accordingly, the BIA claim was not dismissed or struck and only that part of the claim can continue against Perpetual. On August 23, 2019, PwC filed a notice of appeal with the Court of Appeal of Alberta, contesting the entire August 15, 2019 oral decision. On August 26, 2019, Perpetual filed a notice of appeal with the Court of Appeal of Alberta, contesting the BIA claim portion of the oral decision. The appeal proceedings are scheduled to be heard in December of 2020. On November 18, 2019, Perpetual's application to require PwC to post security for costs of the appeal was heard. On January 28, 2020 the Court of Appeal issued its decision requiring PwC to post security with the court in the amount of $240,000 prior to proceeding with its appeal. Applications have been filed by the Trustee to appeal the security for costs decision and alter the reasons for the decision. The Court of Appeal is scheduled to hear these applications in June 2020. On February 25, 2020, Perpetual filed a new application to strike and summarily dismiss the BIA claim on the basis that there was no transfer at undervalue, and Sequoia was not insolvent at the time of the transaction nor caused to be insolvent by the transaction. The Court is scheduled to hear this application in June 2020.

Management expects that the Company is more likely than not to be completely successful in defending this outstanding part of 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.

9. TOU SHARE MARGIN DEMAND LOAN

At December 31, 2019, Perpetual had a $0.1 million (December 31, 2018 – $14.1 million) non-revolving TOU share margin demand loan secured by 1.0 million TOU shares. 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. The TOU share margin demand loan is designated as a financial liability for accounting purposes and measured at amortized cost.

Total loan repayments of $14.0 million were made during 2019. Subsequent to December 31, 2019, the Company sold the remaining TOU shares and repaid the TOU share margin demand loan in full (note 4).

10. REVOLVING BANK DEBT

As at December 31, 2019, the Company's Credit Facility had a Borrowing Limit of $55.0 million (December 31, 2018 – $55.0 million) under which $47.6 million was drawn (December 31, 2018 – $42.6 million) and $2.3 million of letters of credit had been issued (December 31, 2018 – $3.7 million). Borrowings under the Credit Facility bear interest at its lenders' prime rate or Banker's Acceptance rates, plus applicable margins and standby fees. The applicable Banker's Acceptance rate borrowing margins range between 3.0% and 5.5%.

On December 24, 2019, Perpetual's syndicate of Credit Facility lenders completed their semi-annual borrowing base redetermination, reducing the Borrowing Limit from $55 million to $45 million on January 22, 2020, with the maturity date remaining at November 30, 2020. Previously, on March 27, 2019, the Company's lenders confirmed the $55 million Borrowing Limit and the maturity was extended to November 30, 2020. As a result, revolving bank debt has been presented as a current liability on the consolidated statements of financial position as at December 31, 2019.

The next Borrowing Limit redetermination is scheduled on or prior to March 31, 2020. The Credit Facility will revolve until March 31, 2020 and may be extended for a period of up to 364-days subject to approval by the Company's lenders. If not extended, the Credit Facility will cease to revolve, and all outstanding advances will be repayable on November 30, 2020.

The Credit Facility is secured by general, first lien security agreements covering present and future property of the Company and its subsidiaries, with the exception of certain lands pledged to the gas over bitumen royalty financing counterparty (note 13). The Credit Facility also contains provisions which restrict the Company's ability to repay second lien and unsecured debt, and to pay dividends on or repurchase its common shares.

The effective interest rate on the Credit Facility at December 31, 2019 was 7.5%. For the year ended December 31, 2019, if interest rates changed by 1% with all other variables held constant, the annual impact on interest expense and net loss would be $0.5 million.

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

11. TERM LOAN

			December 31, 2019		December 31, 2018	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term loan	March 14, 2021	8.1%	**$ 45,000**	**$ 44,274**	$ 45,000	$ 43,729

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

The term loan has a cross-default provision with the revolving bank debt and contains substantially similar covenants as the revolving bank debt (note 10). 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 revolving bank debt and certain lands pledged to the gas over bitumen royalty financing counterparty.

At December 31, 2019 the term loan is presented net of $0.7 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 9.5%.

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

12. SENIOR NOTES

			December 31, 2019		December 31, 2018	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2019 senior notes	July 23, 2019	8.75%	**$ –**	**$ –**	$ 14,572	$ 14,536
2022 senior notes	January 23, 2022	8.75%	**33,580**	**32,255**	17,918	17,344
Total senior notes			**$ 33,580**	**$ 32,255**	$ 32,490	$ 31,880

On May 7, 2019, Perpetual announced the early redemption of all of the $14.6 million aggregate principal amount of 8.75% senior notes maturing July 23, 2019 (the "2019 Senior Notes") effective June 11, 2019 (the "Redemption Date"). Pursuant to the early redemption, holders of the 2019 Senior Notes would receive CDN $1,000 for each $1,000 principal amount of 2019 Senior Notes (the "Cash Consideration"); or, at the election of the holder, $1,075 principal amount of 8.75% senior notes due January 23, 2022 (the "2022 Senior Notes") for each $1,000 principal amount of 2019 Senior Notes (the "2022 Senior Notes Consideration") plus cash in the amount of $33.32 per $1,000 principal amount of 2019 Senior Notes, representing all accrued and unpaid interest at the Redemption Date.

On June 11, 2019, the Company completed the early redemption of the $14.6 million 2019 Senior Notes. Pursuant to the early redemption, the Company issued $15.7 million of 2022 Senior Notes to fully redeem the 2019 Senior Notes, of which $15.6 million 2022 Senior Notes were issued to entities controlled by or associated with the Company's President and Chief Executive Officer ("CEO"). There was no gain or loss on the exchange. After giving effect to this senior note refinancing, there are $33.6 million 2022 Senior Notes outstanding comprised of $17.9 million 2022 Senior Notes previously outstanding, and the $15.7 million 2022 Senior Notes issued as consideration to redeem the 2019 Senior Notes. Entities controlled by the Company's CEO hold $13.4 million of the 2022 Senior Notes now outstanding. An entity that is associated with the Company's CEO holds an additional $9.1 million of the 2022 Senior Notes now outstanding.

The 2022 Senior Notes bear a fixed interest rate of 8.75% with semi-annual interest payments due January 23 and July 23 of each year. 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. Prior to January 23, 2021, the Company may redeem up to 100% of the senior notes at 103.3% of the principal amount. Subsequent to January 23, 2021, the Company may redeem up to 100% of the senior notes at the principal amount.

At December 31, 2019, the 2022 Senior Notes are recorded at the present value of future cash flows, net of $1.3 million in issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 10.9%.

The senior notes have a cross-default provision with the Company's Credit Facility (note 10). In addition, the senior notes indenture contains restrictions on certain payments including dividends, retirement of subordinated debt and stock repurchases.

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

13. GAS OVER BITUMEN ROYALTY FINANCING

	December 31, 2019	December 31, 2018
Balance, beginning of year	**$ 1,152**	$ 2,739
Payments	**(1,013)**	(1,135)
Change in fair value (note 20)	**732**	(452)
Balance, end of year	**$ 871**	$ 1,152
Gas over bitumen royalty financing – current	**$ 582**	$ 680
Gas over bitumen royalty financing – non-current	**289**	472
Total gas over bitumen royalty financing	**$ 871**	$ 1,152

In 2014, the Company entered into an agreement whereby the Company received cash proceeds of $21.3 million in exchange for an obligation to make a monthly cash payment equivalent to a portion of the Company's monthly gas over bitumen royalty adjustment entitlements until June 2021 when the entitlements expire. Security for the gas over bitumen royalty financing is provided by an interest in certain lands of the Company and by the Company's entitlement to future gas over bitumen royalty adjustments.

The gas over bitumen royalty financing is a hybrid financial instrument comprised of a debt host with an embedded derivative related to indexation of the future cash payments to changes in the future Alberta gas reference price. The Company has designated the gas over bitumen royalty financing as a financial liability which is measured at fair value through profit and loss. For the year ended December 31, 2019, an unrealized loss of $0.7 million (December 31, 2018 – unrealized gain of $0.5 million) is included in non-cash finance expense related to the change in fair value of the gas over bitumen royalty financing.

As at December 31, 2019, if future natural gas prices changed by $0.25 per GJ with all other variables held constant, the fair value of the gas over bitumen royalty financing and after tax net loss for the period would change by $0.2 million (December 31, 2018 – $0.4 million).

14. LEASE LIABILITIES

	Total
January 1, 2019, lease liabilities recognized on adoption of IFRS 16 (note 3b(iv))	**3,126**
Additions	**–**
Interest on lease liabilities (note 20)	**189**
Payments	**(630)**
December 31, 2019	**2,685**
Current	**633**
Non-current	**2,052**
December 31, 2019	**2,685**

Lease terms are negotiated on an individual basis and contain a wide range of terms and conditions. Incremental borrowing rates used to measure the present value of the future lease payments were between 4.3% and 6.6%. During the year, the Company recognized $0.2 million of short-term, low value, and variable lease costs directly in net loss.

15. PROVISIONS

The components of provisions are as follows:

	December 31, 2019	December 31, 2018
Decommissioning obligations (a)	**$ 37,905**	$ 40,097
Restructuring costs (b)	**936**	1,267
Total provisions	**$ 38,841**	$ 41,364
Provisions – current	**$ 2,382**	$ 1,933
Provisions – non-current	**36,459**	39,431
Total provisions	**$ 38,841**	$ 41,364

a) Decommissioning obligations

The following significant assumptions were used to estimate decommissioning obligations:

	December 31, 2019	December 31, 2018
Obligations incurred, including acquisitions	**$ 327**	$ 632
Change in risk free interest rate	**(1,900)**	(287)
Change in estimates	**362**	4,299
Change in decommissioning obligations related to PP&E (note 5)	**(1,211)**	4,644
Obligations settled	**(1,733)**	(1,969)
Obligations disposed (note 5a)	**–**	(500)
Accretion (note 20)	**752**	841
Change in decommissioning obligations	**(2,192)**	3,016
Balance, beginning of year	**40,097**	37,081
Balance, end of year	**$ 37,905**	$ 40,097
Decommissioning obligations – current	**$ 1,446**	$ 1,731
Decommissioning obligations – non-current	**36,459**	38,366
Total decommissioning obligations	**$ 37,905**	$ 40,097

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 Company adjusts the decommissioning obligations at each period end date for changes in the risk-free interest rate. Accretion is calculated on the adjusted balance after considering additions and dispositions to property, plant, and equipment. Decommissioning obligations are also adjusted for revisions to future cost estimates and the estimated timing of costs to be incurred in future years.

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

	December 31, 2019	December 31, 2018
Undiscounted obligations	**$ 40,304**	$ 41,171
Average risk-free rate	**1.8%**	2.2%
Inflation rate	**1.3%**	2.0%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

b) Restructuring costs

	Onerous office contract	Employee downsizing costs	Lease inducement	Total
December 31, 2017	$ 134	$ –	$ 1,470	$ 1,604
Payments	(134)	–	(203)	(337)
December 31, 2018	–	–	1,267	1,267
Lease inducement transferred to lease liability (note 3b)	–	–	(1,267)	(1,267)
Initial recognition	–	1,546	–	1,546
Payments	–	(610)	–	(610)
December 31, 2019	**–**	**936**	**–**	**936**
Current	–	936	–	936
Non-current	–	–	–	–
Balance, end of year	**$ –**	**$ 936**	**$ –**	**$ 936**

In response to the decrease in forward commodity prices, the Company implemented a restructuring plan in the third quarter of 2019, which resulted in the reduction of approximately 25% of its corporate employee head count. Restructuring costs of $1.5 million were expensed into net loss and are anticipated to be fully paid by the end of 2020. Payments made in 2019 with respect to restructuring costs were $0.6 million.

16. CONTRACTUAL OBLIGATIONS

The Company's minimum contractual obligations and lease commitments over the next five years and thereafter excluding estimated interest payments, at December 31, 2019 are as follows:

	2020	2021	2022	2023	2024 and thereafter	Total
Contractual obligations						
Accounts payable and accrued liabilities	13,278	–	–	–	–	13,278
Fair value of derivative liabilities	10,542	2,732	–	–	–	13,274
TOU share margin demand loan, principal amount	100	–	–	–	–	100
Revolving bank debt	47,552	–	–	–	–	47,552
Term loan, principal amount	–	45,000	–	–	–	45,000
Senior notes, principal amount	–	–	33,580	–	–	33,580
Gas over bitumen royalty financing	582	289	–	–	–	871
Lease liabilities	633	567	492	460	533	2,685
Pipeline transportation commitments	3,030	1,870	945	945	945	7,735
Total	**75,717**	**50,458**	**35,017**	**1,405**	**1,478**	**164,075**

17. SHARE CAPITAL

	December 31, 2019		December 31, 2018	
	Shares *(thousands)*	**Amount *($thousands)***	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of year	**60,240**	**$ 1,338,369**	59,263	$ 1,336,838
Issued pursuant to share-based payment plans	**412**	**690**	1,191	1,200
Shares held in trust purchases (b)	**(756)**	**(200)**	(633)	(325)
Shares held in trust issued (b)	**617**	**359**	419	656
Elimination of deficit	**–**	**(1,242,342)**	–	–
Balance, end of year	**60,513**	**$ 96,876**	60,240	$ 1,338,369

At the Company's annual general meeting on May 15, 2019, shareholders approved a resolution to reduce share capital for accounting purposes, without the payment of or a reduction to stated or paid-up capital, by the amount of the deficit on December 31, 2018 of $1,242.3 million.

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 18d). 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 December 31, 2019, 0.8 million shares were held in trust (December 31, 2018 – 0.7 million).

c) Warrants

The following table summarizes the warrants issued:

	Warrants (*thousands*)	**Amount (*$thousands*)**
Balance, December 31, 2017	6,480	$ 923
Warrants exercised for common shares	–	–
Balance, December 31, 2018	6,480	$ 923
Warrants exercised for common shares	–	–
Balance, December 31, 2019	**6,480**	**$ 923**

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. On March 14, 2020, the warrants expired and were not exercised.

d) Per share information

For the year ended		**December 31, 2019**		December 31, 2018
(*thousands, except per share amounts*)				
Net loss – basic	**$**	**(94,015)**	$	(20,380)
Effect of dilutive securities		**–**		–
Net loss – diluted	**$**	**(94,015)**	$	(20,380)
Weighted average shares				
Issued common shares		**61,107**		60,496
Effect of shares held in trust		**(849)**		(457)
Weighted average common shares outstanding – basic and diluted		**60,258**		60,039
Net loss per share – basic and diluted	**$**	**(1.56)**	$	(0.34)

In computing per share amounts for the year ended December 31, 2019, 18.7 million potentially issuable common shares through the share-based compensation plans and warrants (2018 – 18.8 million) were excluded as the Corporation had a net loss.

18. SHARE-BASED PAYMENTS

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

		December 31, 2019		December 31, 2018
Share options (note 18a)	**$**	**452**	$	779
Performance share rights (note 18c)		**1,478**		933
Deferred compensation awards (note 18d)		**365**		861
Share-based payment expense	**$**	**2,295**	$	2,573

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 four years, with expiry occurring five years after issuance.

The following tables summarize information about share options outstanding:

	December 31, 2019		December 31, 2018	
	Average exercise price (*$/share*)	**Share options (*thousands*)**	Average exercise price (*$/share*)	Share options (*thousands*)
Balance, beginning of year	**1.33**	**4,724**	1.67	3,987
Granted	**–**	**–**	0.25	903
Cancelled/forfeited	**1.16**	**(120)**	1.66	(83)
Expired	**–**	**–**	5.97	(83)
Balance, end of year	**1.33**	**4,604**	1.33	4,724

	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*)**
$0.25 to $1.13	864	3.9	0.25	216	0.25
$1.14 to $1.57	1,765	1.5	1.41	1,332	1.42
$1.58 to $2.00	1,975	2.3	1.73	1,065	1.74
Total	4,604	2.3	1.33	2,613	1.45

The Company used the Black Scholes pricing model to calculate the estimated fair value of the outstanding share options and deferred options (note 18d) at the date of grant. During the year ended December 31, 2019, the Company did not grant any additional share options.

	2019	2018
Dividend yield (%)	**–**	0.0
Forfeiture rate (%)	**–**	5.0-10.0
Expected volatility (%)	**–**	60.0
Risk-free interest rate (%)	**–**	2.2
Expected life (years)	**–**	2.6-3.2
Vesting period (years)	**–**	4.0
Contractual life (years)	**–**	5.0
Weighted average grant date fair value	**–**	$ 0.10

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. During the year ended December 31, 2019, 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 18c) vest on the grant date and have a 90-day exercise period. Restricted rights granted upon the exercise of deferred compensation awards (note 18d) vest on the grant date and have a 30-day exercise period. No value is assigned to restricted rights issued pursuant to those plans as the value and expense have been previously recognized over the vesting period of the underlying performance share rights and deferred compensation awards.

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

(*thousands*)	**December 31, 2019**	December 31, 2018
Balance, beginning of year	**–**	–
Granted pursuant to exercise of performance share rights (c)	**215**	1,008
Granted pursuant to exercise of deferred shares (d)	**208**	196
Exercised for common shares[1]	**(423)**	(1,204)
Balance, end of year	**–**	–

(1) May not agree to common shares issued pursuant to share-based payment plans (note 17) due to cashless exercises.

c) Performance share rights plan

The Company has an equity-settled performance share rights plan for the Company's executive officers. 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 18b), at the discretion of the Board of Directors. Performance rights are forfeited if participants of the performance share rights plan leave the organization other than through retirement or termination without cause prior to the vesting date.

The fair value of a performance share rights award is determined at the date of grant by using the closing price of common shares multiplied by the estimated performance multiplier. As at December 31, 2019, performance multipliers of 0.5 have been assumed for those unvested awards granted in 2018 and 2019. Fluctuations in share-based payments may occur due to changes in estimates of performance outcomes. The amount of share-based payment expense is reduced by an estimated forfeiture rate of 5% (2018 – 5%) for outstanding awards. The estimated weighted average fair value of performance share rights granted during the year ended December 31, 2019 was $0.19 per award (2018 – $0.64).

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

(*thousands*)	**December 31, 2019**	December 31, 2018
Balance, beginning of year	**1,465**	1,060
Granted	**1,710**	1,035
Performance adjustment[1]	**(215)**	–
Exercised in exchange for restricted rights[1]	**(215)**	(630)
Cancelled/forfeited	**–**	–
Balance, end of year	**2,745**	1,465

(1) In 2019, vested performance share rights were exercised in exchange for restricted rights based on a performance multiplier of 0.5 (2018 – 1.6).

In 2018, the Company introduced a performance-based long-term incentive awards plan (the "PLTI" plan) for the executive officers. The awards granted pursuant to the plan are tied to specific individual-based performance metrics established by the Board which can be based on "total shareholder return" or other metrics specifically designed to align with value creation for shareholders and to incentivize and retain key executive officers. The awards vest evenly over four years, with expiry occurring five years after issuance. Upon vesting, award holders may be entitled to receive, at the discretion of the Board of Directors, cash, a grant of restricted rights (note 18b), or a combination of cash and restricted rights. Awards granted pursuant to the PLTI plan are included in the table below (note 18d).

Certain awards granted under the PLTI plan contain monetary awards that may be settled in cash, in common shares of the Company, or a combination thereof at the discretion of the Board of Directors, equal to the monetary amount at the time of vesting. These awards are accounted for as cash-settled share-based compensation in which the fair value of the amounts payable under the plan are recognized incrementally as an expense over the vesting period, with a corresponding change in liabilities. Upon exercise of these awards in exchange for cash, the liability is reduced. Upon exercise of these awards in exchange for a variable number of shares, the value in liabilities pertaining to the exercise is recorded as share capital. As at December 31, 2019, $0.4 million had been accrued pursuant to cash-settled share-based compensation awards (December 31, 2018 – $0.4 million).

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 four years, with expiry occurring five years after issuance. The shares purchased by the independent trustee are reported as shares held in trust (note 17b).

The following tables summarize information about the deferred options and performance-based long-term incentive awards:

	December 31, 2019		December 31, 2018	
	Average exercise price *($/share)*	**Deferred options *(thousands)***	Average exercise price *($/share)*	Deferred options *(thousands)*
Balance, beginning of year	**0.84**	**4,165**	1.68	2,268
Granted	**–**	**–**	0.11	2,159
Cancelled/forfeited	**1.18**	**(577)**	1.68	(220)
Expired	**3.16**	**(1)**	4.73	(42)
Balance, end of year	**0.78**	**3,587**	0.84	4,165

	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*)**
$0.01 to $0.24	1,188	3.9	–	297	–
$0.25 to $1.13	786	3.9	0.25	209	0.25
$1.14 to $1.57	603	1.4	1.42	463	1.42
$1.58 to $2.81	1,010	2.3	1.73	545	1.74
Total	3,587	3.0	0.78	1,514	1.09

During the year ended December 31, 2019, 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 18b) 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 17b).

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% (2018 – 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 share 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. The estimated weighted average fair value of these awards granted during the year ended December 31, 2019 was $0.20 per award (2018 – $0.23).

The following table shows changes to these awards:

(*thousands*)	**December 31, 2019**	December 31, 2018
Balance, beginning of year	**1,947**	1,857
Granted	**253**	784
Exercised in exchange for shares held in trust (note 17)	**(617)**	(419)
Exercised in exchange for restricted rights	**(208)**	(196)
Cancelled/forfeited	**(99)**	(79)
Balance, end of year	**1,276**	1,947

19. REVENUE

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 NGL 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 NGL production is mainly 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.

For the year ended December 31, 2019, the Company had sales to three customers which exceeded ten percent of oil and natural gas revenue. The largest customer represented 41% and $30.8 million (2018 – 57% and $49.4 million) of oil and natural gas revenue, and included $28.0 million (2018 – $42.4 million) related to the market diversification contract below. The second largest customer represented 15% and $11.2 million (2018 – 18% and $15.4 million) of oil and natural gas revenue. The third largest customer represented 13% and $9.3 million (2018 – 0% and nil).

Natural gas volumes sold pursuant to the Company's market diversification contract are sold at fixed volume obligations of 40,000 MMBtu/d and priced at daily index prices at each of the market price points, less transportation costs from AECO to each market price point as detailed below.

In the third quarter of 2019, Perpetual extended the term of its market diversification contract by two years. From November 1, 2022 to October 31, 2024, Perpetual will deliver 40,000 MMBtu/d at AECO and receive Malin, Dawn, and Emerson daily index prices less US$0.0775/MMBtu and transportation costs from AECO to the market price point.

In late September 2019, the Company modified its market diversification contract to forgo its right to receive pricing at five North American natural gas hub pricing points for the period commencing December 1, 2019 and ending on October 31, 2020 in consideration for receipt of payment of $2.7 million. The amount has been recognized in revenue as a realized gain on derivatives.

Market/Pricing Point	**November 1, 2020 to October 31, 2022 Daily sales volume (*MMBtu/d*)**	**November 1, 2022 to October 31, 2024 Daily sales volume (*MMBtu/d*)**
Chicago	12,200	–
Malin	10,800	15,000
Dawn	8,000	15,000
Michcon	5,200	–
Empress	3,800	–
Emerson	–	10,000
Total natural gas sales volume obligation	**40,000**	**40,000**

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

	December 31, 2019	December 31, 2018
Oil and natural gas revenue		
Natural gas[(1)]	**$ 39,318**	$ 54,769
Oil	**23,958**	16,390
NGL	**11,085**	14,969
Total oil and natural gas revenue	**$ 74,361**	$ 86,128

(1) Includes revenues related to the market diversification contract of $28.0 million for the year ended December 31, 2019 (2018 – $42.4 million) and $0.7 million related to physical forward sales contracts which settled during the period (2018 - $3.3 million).

Included in accounts receivable at December 31, 2019 is $4.5 million of accrued oil and natural gas sales related to December 2019 production (December 31, 2018 – $7.9 million related to December 2018 production).

20. FINANCE EXPENSE

The components of finance expense are as follows:

		December 31, 2019		December 31, 2018
Cash finance expense				
Interest on revolving bank debt	$	2,880	$	2,226
Interest on TOU share margin demand loan		407		570
Interest on term loan		3,645		3,665
Interest on senior notes		2,921		2,864
Interest on lease liabilities		189		–
Dividend income from TOU share investment		(762)		(618)
Total cash finance expense	$	9,280	$	8,707
Non-cash finance expense				
Amortization of debt issue costs		1,187		1,026
Accretion on decommissioning obligations (note 15a)		752		841
Change in fair value of gas over bitumen royalty financing (note 13)		732		(452)
Total non-cash finance expense	$	2,671	$	1,415
Finance expenses recognized in net loss	$	11,951	$	10,122

21. CHANGES IN NON-CASH WORKING CAPITAL INFORMATION

For the year ended		December 31, 2019		December 31, 2018
Accounts receivable	$	3,875	$	5,138
Prepaid expenses and deposits		(16)		(201)
Accounts payable and accrued liabilities[(1)]		(2,890)		(15,242)
Change in non-cash working capital	$	969	$	(10,305)

(1) Includes $0.4 million (December 31, 2018 – $0.4 million) of cash-settled share-based payment awards (note 18c).

The change in non-cash working capital has been allocated to the following activities:

For the year ended		December 31, 2019		December 31, 2018
Operating	$	4,602	$	2,541
Financing		–		–
Investing		(3,633)		(12,846)
Change in non-cash working capital	$	969	$	(10,305)

22. FINANCIAL RISK MANAGEMENT

The Board of Directors has overall responsibility for the establishment and oversight of the Company's risk management framework and has implemented and monitors compliance with risk management policies.

The Company's risk management policies are established to identify and analyze the risks faced by the Company, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Company's activities.

a) Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Company's receivables from joint venture partners, oil and natural gas marketers and derivative contract counterparties.

Receivables from oil and natural gas marketers are normally collected on the 25th day of the month following sales. The Company's policy to mitigate credit risk associated with these balances is to establish marketing relationships with large, well established purchasers. The Company historically has not experienced any significant collection issues with its oil and natural gas marketing receivables. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Company attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, the receivables are generally from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on industry factors such as commodity price fluctuations, escalating costs, the risk of unsuccessful drilling and oil and gas production; in addition, further risk exists with joint venture partners as disagreements occasionally arise that increase the potential for non-collection. The Company does not typically obtain collateral from oil and natural gas marketers or joint venture partners, however, the Company does have the ability in some cases to withhold production or amounts payable to joint venture partners in the event of non-payment.

The Company manages the credit exposure related to derivatives by engaging in risk management transactions with credit worthy counterparties, and periodically monitoring counterparty credit assessments.

The combined carrying amount of accounts receivable and fair value of derivative assets as at December 31, 2019 was $5.1 million (December 31, 2018 – $19.8 million), representing the Company's maximum credit exposure. The Company's credit provisions are represented by its loss allowance based on lifetime expected credit losses as at December 31, 2019 of $0.9 million (December 31, 2018 – $1.1 million). The amount of the loss allowance was determined based on historical credit loss experience, adjusted for forward-looking factors specific to the debtors and the economic environment. The total amount of accounts receivables 90 days past due amounted to $0.8 million as at December 31, 2019 (December 31, 2018 – $1.1 million).

b) Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses or risking harm to the Company's reputation (note 1).

c) Market risk

Market risk is the risk that changes in market prices such as foreign exchange rates, commodity prices and interest rates will affect the Company's net loss or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Company utilizes both financial derivatives and fixed price physical delivery sales contracts to manage market risks related to commodity prices, and foreign currency rates. All such transactions are conducted in accordance with the Company's Risk Management Policy, which has been approved by the Board of Directors.

i) Commodity price risk

Commodity price risk is the risk that the fair value or future cash flow will fluctuate as a result of changes in commodity prices. Commodity prices for oil and natural gas are impacted not only by the relationship between the Canadian and United States dollar, but also by world economic events that dictate the levels of supply and demand. The Company manages commodity price risk using various financial derivatives and fixed price physical delivery sales contracts.

As at December 31, 2019, the Company has variable priced physical natural gas sales contracts based on future market prices. These contracts are not classified as non-financial derivatives since the settlement price corresponds directly with fluctuations in natural gas prices.

Natural gas contracts

At December 31, 2019, the Company had entered into the following basis differential contracts between AECO and NYMEX:

Term	Settlement	Sold/bought	Volumes (*MMBtu/d*)	AECO-NYMEX differential (*US$/MMBtu*)	Fair Value (*$ thousands*)
January 2020 – December 2020	Physical	Sold	12,500	(1.41)	(3,562)
January 2020 – December 2020	Financial	Sold	15,000	(1.41)	(4,302)
January 2021 – December 2021	Physical	Sold	15,000	(1.31)	(2,732)

Natural gas contracts - sensitivity analysis

As at December 31, 2019, if future AECO-NYMEX differential prices changed by US$0.15/MMBtu with all other variables held constant, the fair value of derivatives and net loss for the period would change by $2.8 million. Fair value sensitivity was based on published forward AECO and NYMEX prices.

Oil contracts

At December 31, 2019, the Company had entered into the following financial fixed price oil sales arrangements which settle in Cdn$:

Term	Volumes (*bbls/d*)	WTI (*Cdn$/bbl*)	Fair Value (*$ thousands*)
January 2020 – December 2020	250	50.00	(141)

At December 31, 2019, the Company had entered into the following financial fixed price oil sales arrangements which settle in US$:

Term	Volumes (*bbls/d*)	WTI (*US$/bbl*)	Fair Value (*$ thousands*)
January 2020 – October 2020	1,000	54.28	(1,944)

At December 31, 2019, the Company had entered into the following financial oil basis differential arrangements between WTI and WCS:

Term	Volumes (*bbls/d*)	WTI-WCS differential (*US$/bbl*)	Fair Value (*$ thousands*)
January 2020 – December 2020	750	(18.75)	(168)

Oil contracts - sensitivity analysis

As at December 31, 2019, if future oil prices or WTI-WCS differentials changed by US$5.00 per boe with all other variables held constant, the fair value of derivatives and net loss for the period would change by $4.1 million. Fair value sensitivity was based on published forward WTI and WCS prices.

NGL contracts

At December 31, 2019, the Company had entered into the following financial NGL basis differential arrangements between WTI and Edmonton condensate pricing:

Term	**Volumes (*bbls/d*)**	**WTI-Edmonton condensate differential (*US$/bbl*)**	**Fair Value (*$ thousands*)**
January 2020 – June 2020	350	(6.15)	(351)

NGL contracts - sensitivity analysis

As at December 31, 2019, if future WTI-Edmonton condensate differential prices changed by US$0.50/bbl per boe with all other variables held constant, the fair value of derivatives and net loss for the period would change by a nominal amount. Fair value sensitivity was based on published forward WTI and Edmonton condensate prices.

Foreign exchange contracts

At December 31, 2019, the Company had entered into the following US$ forward sales arrangements to manage the Company's exposure to US$ denominated crude oil sales:

Term	**Notional (*US$ thousands/month*)**	**Strike rate (*US$/Cdn$*)**	**Fair Value (*$ thousands*)**
January 2020 – March 2020	2,000	1.29	(74)

Foreign exchange contracts - sensitivity analysis

As at December 31, 2019, 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 $0.6 million. Fair value sensitivity was based on published forward US$/Cdn$ rates.

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

	December 31, 2019	December 31, 2018
Physical natural gas contracts	**$ (6,294)**	$ 5,293
Financial natural gas contracts	**(4,302)**	4,336
Financial oil contracts	**(2,253)**	1,289
Financial NGL contracts	**(351)**	–
Financial foreign exchange contracts	**(74)**	(2,299)
Fair value of derivatives	**$ (13,274)**	$ 8,619
Derivative assets – current	**–**	7,012
Derivative assets – non-current	**–**	3,906
Derivative liabilities – current	**(10,542)**	(1,405)
Derivative liabilities – non-current	**(2,732)**	(894)
Fair value of derivatives	**$ (13,274)**	$ 8,619

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

	December 31, 2019	December 31, 2018
Unrealized gain (loss) on physical natural gas contracts	**(11,587)**	4,084
Unrealized gain (loss) on financial natural gas contracts	**(8,638)**	2,830
Unrealized gain (loss) on financial oil contracts	**(3,542)**	1,132
Unrealized gain (loss) on financial NGL contracts	**(351)**	–
Unrealized gain (loss) on forward foreign exchange contracts	**2,225**	(2,299)
Unrealized change in fair value of derivatives	**(21,893)**	5,747
Realized gain (loss) on financial natural gas contracts (1)	**3,917**	4,141
Realized gain (loss) on financial oil contracts	**(3,818)**	(820)
Realized gain (loss) on financial NGL contracts	**(328)**	–
Realized gain (loss) on forward foreign exchange contracts	**(560)**	(250)
Change in fair value of derivatives	**(22,682)**	8,818

(1) Includes early settlement of $2.7 million related to the market diversification contract (note 19).

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:

				Fair value		
As at December 31, 2019	**Gross**	**Netting[1]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
TOU share investment	15,220	–	15,220	15,220	–	–
Fair value of derivatives	159	(159)	–	–	–	–
Financial liabilities						
Financial liabilities at amortized cost						
TOU share margin demand loan	(100)	–	(100)	(100)	–	–
Revolving bank debt	(47,552)	–	(47,552)	(47,734)	–	–
Senior notes	(32,255)	–	(32,255)	–	(31,691)	–
Term loan	(44,274)	–	(44,274)	–	–	(45,000)
Fair value through profit and loss						
Fair value of derivatives	(13,433)	159	(13,274)	–	(13,274)	–
Gas over bitumen royalty financing	(871)	–	(871)	–	–	(871)

(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.

				Fair value		
As at December 31, 2018	**Gross**	**Netting[1]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
TOU share investment	28,132	–	28,132	28,132	–	–
Fair value of derivatives	14,092	(3,174)	10,918	–	10,918	–
Financial liabilities						
Financial liabilities at amortized cost						
TOU share margin demand loan	(14,109)	–	(14,109)	(14,144)	–	–
Revolving bank debt	(42,561)	–	(42,561)	(42,689)	–	–
Senior notes	(31,880)	–	(31,880)	–	(30,126)	–
Term loan	(43,729)	–	(43,729)	–	–	(45,000)
Fair value through profit and loss						
Fair value of derivatives	(5,473)	3,174	(2,299)	–	(2,299)	–
Gas over bitumen royalty financing	(1,152)	–	(1,152)	–	–	(1,152)

(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.

23. DEFERRED INCOME TAXES

The provision for income taxes in the consolidated financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to the Company's loss before income tax. This difference results from the following items:

	December 31, 2019	December 31, 2018
Net loss before income tax	**$ (94,015)**	$ (20,380)
Combined federal and provincial tax rate	**26.5%**	27.0%
Computed income tax expense (recovery)	**(24,914)**	(5,503)
Increase (decrease) in income taxes resulting from:		
Non-deductible expenses	**124**	695
Non-taxable capital loss	**425**	1,293
Other	**891**	729
Change in unrecognized tax asset	**23,474**	2,786
Deferred income tax expense	**$ –**	$ –

The following table summarizes the deferred income tax liabilities of the Company and its subsidiaries, which are offset against certain deferred income tax assets:

For the years ended	**December 31, 2019**	December 31, 2018
Liabilities:		
Senior notes	**$ 351**	$ 164
Term loan	**192**	353
Fair value of derivatives	**–**	2,948
Right-of-use-assets	**391**	–
Total deferred income tax liabilities	**934**	3,465
Assets:		
Decommissioning obligations	**$ (934)**	$ (3,465)

The unused tax losses and deductible temporary differences included in the Company's unrecognized deferred income tax assets are as follows:

For the years ended	**December 31, 2019**	December 31, 2018
Non-capital losses	**$ 201,739**	$ 179,021
Capital losses	**151,553**	142,552
Property, plant and equipment	**83,396**	33,189
Decommissioning obligations	**34,379**	27,300
Fair value of derivatives	**13,275**	2,300
TOU share investment	**13,261**	19,055
Share and debt issue costs	**2,813**	2,742
Lease liabilities	**2,686**	–
Other	**1,807**	2,383
	$ 504,909	$ 408,542

At December 31, 2019, the unused non-capital losses expire between 2024 and 2039, and unused capital losses have no expiry date. The deductible temporary differences do not expire under current tax legislation. The oil and natural gas properties and facilities owned by the Company and its subsidiaries have an approximate tax basis of $302 million (December 31, 2018 – $319 million) available for future use as deductions from taxable income.

Deferred income tax assets have not been recognized in respect of these unused tax losses and temporary differences because it is not probable that future taxable profit will be available against which the Company can utilize the benefits.

24. KEY MANAGEMENT PERSONNEL

The Company has defined key management personnel as executive officers, as well as the Board of Directors, as they have the collective authority and responsibility for planning, directing and controlling the activities of the Company. The following table outlines the total compensation expense for key management personnel:

For the years ended	**December 31, 2019**	December 31, 2018
Short-term compensation	**$ 2,434**	$ 2,593
Share-based payments	**1,987**	1,717
	$ 4,421	$ 4,310

25. SUPPLEMENTAL DISCLOSURE

The Company's consolidated statements of loss and comprehensive loss are prepared primarily by nature of expense, except for employee compensation costs which are included in both production and operating and general and administrative expenses.

The following table details the amount of total employee compensation costs included in production and operating and general and administrative expenses in the consolidated statements of loss and comprehensive loss.

For the years ended	**December 31, 2019**	December 31, 2018
Production and operating	**$ 2,009**	$ 2,006
General and administrative	**8,234**	8,685
Share-based payments	**2,295**	2,573
Restructuring costs	**1,546**	–
	$ 14,084	$ 13,264

CORPORATE INFORMATION

DIRECTORS

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

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

OFFICERS

Susan L. Riddell Rose
President, Chief Executive Officer and Director
W. Mark Schweitzer
Vice President, Finance and Chief Financial Officer
Ryan M. Goosen
Vice President, Business Development and Land
Jeffrey R. Green
Vice President, Corporate and Engineering Services
Linda L. McKean
Vice President, Production and Development
Marcello M. Rapini
Vice President, Marketing

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Bank of Montreal
Bank of Nova Scotia

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

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