2020 ANNUAL RESULTS

PERPETUAL ENERGY

TO SHAREHOLDERS

Perpetual cautiously navigated the "double black swan" events that drove the global energy system into disarray in 2020. The Company began the year with a positive game plan focused on the emerging Clearwater oil play in eastern Alberta. A successful drilling program in the first quarter of 2020 proved up an extensive drilling inventory in our Ukalta area and refined our well design and drilling mud system. This capital activity came to an abrupt halt with the onset of the coronavirus pandemic and the collapse of the global oil demand system in early-March.

The COVID-19 emergency response triggered massive economic contraction as governments around the world locked down citizens in an effort to slow infection rates and hospitalizations. In the midst of this public health crisis and corresponding energy demand collapse, members of the Organization of Petroleum Exporting Countries ("OPEC") stood off against one another to trigger an oil price war, choosing not to constrain supply to manage the global supply-demand imbalance. Investment was put on pause in every sector and in every country around the globe, waiting for signs of stability and more clarity on the future. Perpetual responded quickly to first and foremost keep our people safe and healthy. Our team quickly adopted work from home strategies with no significant disruptions, and office and field protocols were activated that have ebbed and flowed with the multiple waves of coronavirus lockdowns. Heavy crude oil production was temporarily shut-in to minimize operating losses and preserve reserves and cost reduction measures were implemented across the business. The Company actively engaged with industry organizations and government to influence regulatory changes, accelerating discussions that became more urgent to stabilize Canadian oil and gas businesses along with the rest of the Canadian economy.

The West Texas Intermediate ("WTI") light oil benchmark price fell to unprecedented negative levels in late April and averaged just US$27.85/bbl for the second quarter of 2020. Exploration and production companies operating in every basin around the world ceased drilling activities and wells were shut-in to preserve value, helping to re-balance market fundamentals. June marked the beginning of the slow road to recovery. The actions of governments and central banks to regain financial stability and support citizens and economies began to bear fruit. OPEC+ shifted their collective stance to one of cooperation, and by instituting supply restrictions oil prices began to stabilize. The WTI oil price stabilized but remained largely range-bound through the second half of 2020 at US$40.00 to $45.00/bbl. While shut-in supply was slowly restored, low rig counts kept North American production in check. Late in the year and into 2021, amidst optimism of vaccine availability and discipline by OPEC, market sentiment has shifted positive and the forward market for WTI oil prices in 2021 has recently pushed into the US$55.00 to $60.00/bbl range. Importantly, the discount for Western Canadian Select ("WCS") heavy oil prices narrowed materially as pipeline constraints eased, supporting the market price Perpetual receives at its multiple Alberta heavy oil sales delivery points.

Although the factors that drove instability were somewhat different than for oil, natural gas prices in 2020 did not escape volatility. NYMEX natural gas prices experienced a precipitous decline coming into 2020, as associated gas supply primarily from oil-focused drilling in the Permian Basin surged into an unseasonably warm winter. Higher than normal natural gas storage inventories in the United States, Europe and Asia combined with the overprint of industrial demand destruction induced by the pandemic and slowed LNG exports from North America through much of the summer, putting downward pressure on natural gas prices. Western Canada's depleted gas storage network filled to capacity through the summer, pulling basis differentials to very tight levels and establishing the AECO hub as a bright light for natural gas prices on a relative basis. With rig utilization rates at extremely low levels, depletion began to take hold of the supply trajectory coming into this past winter. Alas though, winter never truly materialized and natural gas prices weakened, only to whipsaw higher with the short-lived polar vortex event that gripped North American for a few weeks in February. Warm, spring-like weather across the continent has now returned and inventory levels exiting the winter heating season are not overly concerning to market players. Natural gas prices for the next six to twelve months will be shaped by the complex interplay of summer cooling demand, exports, storage levels and producer response to oil and natural gas price levels.

To enhance liquidity, improve the balance sheet and optimize value, Perpetual sold a 50% working interest in the East Edson liquids-rich natural gas property in West Central Alberta on April 1, 2020. The transaction transferred operatorship to a strong industry partner and included the commitment to carry Perpetual's share of capital for the next eight wells drilled in the property, seven of which are now drilled and on production. As anticipated, production levels have been restored to more fully utilize the existing processing capacity, thereby improving operating netbacks. In addition, materially stronger capital efficiencies have been established through the operator's scale of activity. The well design and inter-well spacing at East Edson has been further optimized, reducing the future development costs estimated for the development of the Wilrich reserves by close to 63% even after adjusting for the sale of the 50% working interest.

The Company's heavy crude oil production was restored in stages through May to July as improving WCS prices supported positive returns. Strong performance of the new wells drilled at Ukalta contributed to a material year-over-year increase in recognized Clearwater reserves to represent 10% of total Company reserves at year-end 2020. Perpetual successfully secured additional prospective acreage on the Clearwater play, and is now very excited about the high potential, profitable growth opportunity inherent in the close to 90 net sections of promising Clearwater resource captured. At current forward market prices for WCS, the Clearwater play is highly profitable. Upon completion of its debt refinancing, the Company is poised to execute an extensive drilling program across multiple properties to refine the multi-lateral drilling technology, delineate the Clearwater resource, and prove up a profitable development plan. At the same time, we will continue to pursue additional land capture in the Clearwater play fairway and analogous targets.

The Board of Directors and Management are grateful for the dedication and resiliency of our team and the support of our stakeholders. It is with optimism and excitement that we put 2020 in the books and now look forward to 2021, and particularly unlocking the inherent potential of our Clearwater play.

Susan Riddell Rose

SUE RIDDELL ROSE
President and Chief Executive Officer

March 25, 2021

2020 ANNUAL HIGHLIGHTS

2020 FINANCIAL AND OPERATING HIGHLIGHTS

Capital Spending, Production and Operations

- Perpetual's 2020 exploration and development spending was $6.0 million, down 54% from the prior year. Capital investment was focused on the Clearwater play in Eastern Alberta, where total spending of $5.5 million included costs to drill, complete and tie-in four (4.0 net) heavy crude oil wells in the Ukalta area. The program successfully demonstrated enhanced capital efficiency and performance, de-risked additional development drilling inventory, and resulted in reserve finding and development ("F&D") costs of $9.26/boe (2019 – $17.27/boe) on a proved and probable basis, including changes in future development capital ("FDC"). The Clearwater drilling program, combined with better than forecast well performance and farm-in arrangements, contributed to a year-over-year increase in Clearwater proved and probable reserves of 2.7 million bbls.
- For the year ended December 31, 2020, Perpetual executed $1.0 million (2019 – $1.7 million) of abandonment and reclamation projects, of which $0.8 million was funded by Alberta's Site Rehabilitation Program ("SRP").
- On April 1, 2020, the Company sold a 50% working interest in its East Edson property in West Central Alberta to a third party for consideration including a cash payment of $35 million and the carried interest funding of the drill, complete and tie-in costs for an eight well drilling program (the "East Edson Transaction"). Five (2.5 net) horizontal Wilrich carried interest wells were drilled, completed and tied-in during the year at the 50% owned East Edson property. Drilling of two (1.0 net) additional East Edson carried interest wells commenced in late January 2021 and were brought on production in March 2021. The final carried interest well is expected to be drilled and on production in the third quarter of 2021.
- Production in 2020 averaged 5,012 boe/d (29% heavy crude oil and NGL), a decrease of 44% from 2019. The decrease was due primarily to the closing of the East Edson Transaction, combined with the temporary shut-in of heavy crude oil production throughout the second quarter in response to the abrupt drop in oil prices experienced due to local and global supply and demand imbalances and the COVID-19 pandemic. As Western Canadian Select ("WCS") prices improved from their April lows, the Company began reactivating certain low-cost heavy crude oil production in mid-May 2020, and has continued to ramp up production as oil prices improve.
- Perpetual's operating netback was $8.4 million ($4.57/boe), down 78% from 2019. The decrease was due to a 44% decline in year-over-year production, combined with the impact of lower realized natural gas and NGL prices of 69% and 23% respectively.

Financial Highlights

- Realized revenue was $30.2 million in 2020, down $43.4 million (59%) from 2019 due to the combined effect of lower production related to the East Edson Transaction, heavy crude oil shut-ins, and net hedging losses. On a unit-of-production basis, realized revenue was $16.46/boe, 27% lower than the prior year due primarily to lower realized natural gas and NGL prices. Compared to the AECO Daily Index price of $2.23/Mcf, realized natural gas prices were negatively impacted by physical and financial AECO-NYMEX basis differential hedging and market diversification contract losses of $12.7 million ($1.62/Mcf). For the year ended December 31, 2020, Perpetual's realized oil price was $49.37/bbl, up 10% from $44.87/bbl in 2019. Realized oil prices were improved by hedging gains of $7.5 million ($19.05/bbl) during the year.
- Cash costs were $36.3 million in 2020, down $20.5 million (36%) from 2019. The decrease was due primarily to lower royalties, production and operating, and transportation costs associated with the 44% decrease in production, combined with lower general and administrative expense driven by a 25% reduction in Perpetual's corporate employee head count that was implemented late in the third quarter of 2019, along with the reduction in work hours and corresponding employee compensation to 80%, effective April 1, 2020. In 2020, the Company received total payments of $1.3 million from the Canada Emergency Wage Subsidy ("CEWS") and Canada Emergency Rent Subsidy ("CERS") programs which were recognized as a reduction to general and administrative and production and operating expenses of $1.0 million and $0.3 million, respectively. In addition, the semi-annual interest payment of $1.8 million that was payable December 31, 2020, was deferred by the Company's Term Loan lender and added to the principal amount owing as a condition of the Credit Facility lenders agreeing to extend the Credit Facility maturity to March 1, 2021.
- Net loss for 2020 was $61.6 million ($1.01/share), down from $94.0 million in 2019 ($1.56/share). The net loss in 2020 was impacted by aggregate non-cash impairment charges of $42.5 million, comprised of $60.5 million of impairment charges booked at March 31, 2020, partially offset by an $18.0 million impairment reversal recorded at December 31, 2020.
- Net cash flows used in operating activities were $9.5 million in 2020, down $27.3 million compared to 2019. The decrease was due primarily to the $43.4 million reduction in realized revenue, partially offset by a $20.5 million reduction in cash costs.
- For the year ended December 31, 2020, adjusted funds flow was negative $7.8 million ($0.13/share), down $22.3 million from $14.5 million ($0.24/share) in 2019 as the impact of the 44% year-over-year decrease in production combined with lower realized natural gas and NGL prices outweighed the 36% decrease in cash costs.
- At December 31, 2020, Perpetual had total net debt of $105.0 million, down $13.1 million (11%) from December 31, 2019. The Company's Credit Facility had a Borrowing Limit of $20.0 million (December 31, 2019 – $55.0 million) under which $17.5 million was drawn (December 31, 2019 – $47.6 million).

FINANCIAL AND OPERATING HIGHLIGHTS

	Three Months ended December 31			Year ended December 31		
($Cdn thousands, except volume and per share amounts)	**2020**	2019	Change	**2020**	2019	Change
Financial						
Oil and natural gas revenue	**8,178**	15,830	(48%)	**29,486**	74,361	(60%)
Net income (loss)	**14,443**	(32,498)	(144%)	**(61,597)**	(94,015)	(34%)
Per share – basic and diluted[2]	**0.24**	(0.54)	(144%)	**(1.01)**	(1.56)	(35%)
Cash flow from (used in) operating activities	**(1,104)**	(1,290)	(14%)	**(9,533)**	17,806	(154%)
Per share[2]	**(0.02)**	(0.02)	–	**(0.16)**	0.30	(153%)
Adjusted funds flow[1]	**1,240**	340	265%	**(7,787)**	14,534	(154%)
Per share[1][2]	**0.02**	0.01	100%	**(0.13)**	0.24	(154%)
Revolving bank debt	**17,495**	47,552	(63%)	**17,495**	47,552	(63%)
Senior notes, principal amount	**33,580**	33,580	–	**33,580**	33,580	–
Term loan, principal amount	**46,823**	45,000	4%	**46,823**	45,000	4%
TOU share margin demand loan, principal amount	**–**	100	(100%)	**–**	100	(100%)
TOU share investment	**–**	(15,220)	(100%)	**–**	(15,220)	(100%)
Net working capital deficiency[1]	**7,099**	7,068	–	**7,099**	7,068	–
Total net debt[1]	**104,997**	118,080	(11%)	**104,997**	118,080	(11%)
Net capital expenditures						
Capital expenditures	**466**	1,995	(77%)	**5,939**	12,939	(54%)
Net proceeds on acquisitions and dispositions	**–**	–	–	**(34,528)**	–	100%
Net capital expenditures	**466**	1,995	(77%)	**(28,589)**	12,939	(321%)
Common shares outstanding *(thousands)*						
End of period[3]	**61,305**	60,513	1%	**61,305**	60,513	1%
Weighted average – basic and diluted	**61,266**	60,444	1%	**61,013**	60,258	1%
Operating						
Daily average production						
Conventional natural gas *(MMcf/d)*	**19.5**	36.6	(47%)	**21.5**	42.3	(49%)
Heavy crude oil *(bbl/d)*	**1,241**	1,275	(3%)	**1,082**	1,224	(12%)
NGL *(bbl/d)*	**237**	606	(61%)	**346**	719	(52%)
Total *(boe/d)*[5]	**4,730**	7,991	(41%)	**5,012**	8,988	(44%)
Average prices						
Realized natural gas price *($/Mcf)*[4]	**1.46**	2.00	(27%)	**0.85**	2.77	(69%)
Realized oil price *($/bbl)*[4]	**52.60**	43.85	20%	**49.37**	44.87	10%
Realized NGL price *($/bbl)*[4]	**38.03**	43.93	(13%)	**31.40**	41.01	(23%)
Wells drilled						
Conventional natural gas – gross (net)	**3 (1.5)**	– (–)		**5 (2.5)**	– (–)	
Heavy crude oil – gross (net)	**– (–)**	– (–)		**4 (4.0)**	5 (5.0)	
Total – gross (net)	**– (–)**	– (–)		**9 (6.5)**	5 (5.0)	

(1) These are non-GAAP measures. Please refer to "Advisories" below.
(2) Based on weighted average basic common shares outstanding for the period.
(3) All common shares are net of shares held in trust (2020 – 556; 2019 – 801). See "Note 16 to the Audited Consolidated Financial Statements".
(4) Realized natural gas, oil, and NGL prices included 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.
(5) Please refer to "Volume conversions" on page 14 of these annual results.

ADVISORIES

The letter to shareholders and 2020 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 13 and 14, "*Management's Discussion and Analysis – Critical Accounting Estimates – Forward-Looking Information and Statements*" on pages 35 and 36 and "*Management's Discussion and Analysis – Risk Factors – Oil and Gas Advisories*" on page 36 of these annual results.

2020 STRATEGIC PRIORITIES

Progress was made to advance Perpetual's top five strategic priorities for 2020 which include:

1. Improve balance sheet and liquidity;
2. Maximize value of base assets;
3. Grow value and impact of the Clearwater play;
4. Resolve the Sequoia litigation; and
5. Advance technology-driven diversifying new ventures.

Improve balance sheet and liquidity

- In January 2020, the Company sold its remaining 1.0 million Tourmaline Oil Corp. ("TOU") shares for net cash proceeds of $14.3 million. 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.
- Cash proceeds of $35 million from the East Edson Transaction were used to further reduce the Credit Facility. As a key element of the consideration in the East Edson Transaction, Perpetual was carried for its 50% working interest in the five (2.5 net) wells drilled, completed, and brought onstream at East Edson in 2020.
- The Company invested $6.0 million on exploration and development, almost exclusively targeting Clearwater development. In response to the significant decline in global oil prices which began in late-March, all heavy oil focused capital investment for the remainder of 2020 was deferred.
- A reduction in abandonment and reclamation spending was enabled by the Alberta Energy Regulator's ("AER") cancellation of area-based closure expenditure requirements for 2020 and the introduction of the Government of Alberta's Site Rehabilitation Program ("SRP") funding. Cash expenditures on decommissioning obligations totaled $0.2 million ($1.0 million inclusive of SRP funding) as compared to $1.7 million in 2019.
- General and administrative ("G&A") costs were down 33% ($3.8 million) year-over-year, driven by a 25% reduction in the Company's corporate employee head count that was implemented in the third quarter of 2019, combined with a suspension in savings plan compensation and a reduction in work hours and corresponding employee compensation to 80% effective April 1, 2020. The Company received payments through the Canada Emergency Wage Subsidy program of $1.3 million, $1.0 million of which was recognized as a reduction to G&A. These reductions were partially offset by legal costs related to the Sequoia Litigation and lower overhead recoveries triggered by reduced capital spending activity and the transfer of operatorship with the 50% sale of East Edson.
- Perpetual has in place a market diversification contract that effectively shifts the sales point for natural gas on 40,000 MMBtu/d from AECO hub to a basket of five North American natural gas hub pricing points (Chicago, Malin, Dawn, Michcon and Emerson). With changes made to TC Energy's operating protocol in the fourth quarter of 2019, Perpetual recorded AECO-NYMEX basis differential hedging and market diversification contract losses of $12.7 million in 2020. During the second quarter of 2020, the Company locked-in remaining AECO-NYMEX basis hedge positions by entering into substantially offsetting hedge arrangements for the remainder of 2020 and 2021. The Company expects to realize a further loss of $3.4 million in 2021 on these locked-in positions. In February 2021, the Company's outstanding 10,000 MMBtu/d market diversification contract obligations for 2021 were eliminated for the period of April 1, 2021 to October 31, 2021 in consideration for the payment of $1.4 million over the term of the associated contract volumes. Perpetual is forecasting AECO-NYMEX basis differential hedging and market diversification contract losses for 2021 of $5.8 million. The market diversification contract expires in October 2024.
- Concurrent with the shut-in of heavy crude oil production in late-March, financial WTI oil hedges were crystallized, contributing to realized hedging gains on oil contracts of $7.5 million in 2020.
- At December 31, 2020, Perpetual had total net debt of $105.0 million, down $13.1 million (11%) from December 31, 2019 due to the closing of the East Edson Transaction on April 1, 2020 for consideration including cash proceeds of $35 million. The cash proceeds from the East Edson Transaction were used to repay bank debt.
- Perpetual had available liquidity at December 31, 2020 of $1.6 million, comprised of the $20 million Credit Facility Borrowing Limit, less current borrowings and letters of credit of $17.5 million and $0.9 million, respectively.
- On January 22, 2021, the Company announced the completion of a Court-approved plan of arrangement whereby the 2022 Senior Notes were exchanged for new 8.75% secured third lien notes due January 23, 2025. The 2025 Senior Notes have been issued under a trust indenture that contains substantially the same terms as the 2022 Senior Notes, other than the 2025 Senior Notes are secured on a third lien basis and allow for the semi-annual interest payments to be paid at Perpetual's option, in either cash, or in additional 2025 Senior Notes. The Company elected to pay the January 23, 2021 interest payment of $1.5 million by a PIK Interest Payment which increased the principal amount of the 2025 Senior Notes outstanding to $35.0 million. Perpetual intends to pay in-kind the 2025 Senior Notes semi-annual interest payment due July 23, 2021.
- The Credit Facility Borrowing Limit is scheduled to be redetermined and the revolving credit period extended on or before April 30, 2021. If not extended by April 30, 2021, the Credit Facility will cease to revolve, and all outstanding advances will be repayable.
- The maturity date applicable to the Company's second lien Term Loan, originally scheduled to mature March 14, 2021, has been extended to May 14, 2021. The extension of the Term Loan and first lien revolving credit facility provides additional time to finalize negotiations with its lenders and for the Company to explore opportunities to enhance its liquidity.

Maximize value of base assets

- In accordance with the terms of the East Edson Transaction, the Purchaser drilled, completed and tied-in five (2.5 net) horizontal Wilrich carried interest wells during the year at the 50% owned East Edson property, with the next two (1.0 net) wells on production in March 2021. The final carried interest well is scheduled to be drilled, completed and tied-in during the third quarter of 2021.
- Other spending on the Company's East Edson property in West Central Alberta was limited to just $0.5 million and was directed to maintenance projects at the West Wolf plant.
- The East Edson development plan has been revised to reflect increased well spacing, longer extended-reach wells, and reduced capital costs per well related to the Purchaser's scale of operations as demonstrated by the execution of the 2020 carried interest drilling program. After giving effect to the 50% working interest reduction as a result of the East Edson Transaction, future development capital ("FDC") to develop the Company's remaining 50% interest in the recognized Wilrich reserves decreased by 63% or $102.9 million on a proved plus probable basis, while proved reserves increased by 8% from prior year levels.
- Production in West Central Alberta averaged 3,525 boe/d in 2020 (90% conventional natural gas), down 51% year-over-year, reflecting the sale of the 50% working interest in the East Edson property and natural declines.
- NGL yields at East Edson were 18.2 bbls per MMcf of conventional natural gas production (61% condensate) in 2020, comparable to the prior year (2019 – 18.6 bbls per MMcf and 61% condensate).
- Production and operating costs in West Central Alberta were down by $2.8 million (39%) over the prior year, commensurate with the 50% working interest sale at East Edson part way through the year. Production and operating expenses on a unit-of-production basis were up 25% to $3.42/boe, compared to $2.74/boe for 2019 which reflects lower production over a largely fixed cost operating base. As production grows to approach infrastructure capacity at East Edson, unit operating costs are forecast to be restored to prior levels.
- West Central operating netbacks were $3.43/boe in 2020, down 68% from the prior year period (2019 – $10.70/boe). The decrease was driven primarily by lower realized natural gas prices as a result of hedging losses on locked-in AECO-NYMEX basis differential contracts and market diversification contract losses.
- Production at Mannville averaged 1,101 boe/d during the year, comprised of 2.5 MMcf/d conventional natural gas and 690 bbl/d heavy crude oil. In response to the precipitous drop in oil prices late in the first quarter, heavy oil sales were deferred in late-March. At Mannville, approximately 700 bbl/d continued to produce into tanks to fill onsite storage, with an additional 300 bbl/d shut-in completely to eliminate water handling, trucking and other costs. The Company closely monitored market dynamics in an effort to optimize value of its stored tank volumes and developed heavy oil reserves. Close to 85% of Mannville production is associated with pads which are fully connected via pipeline for water handling associated with production and injection. Operating costs on these pads are lower than the average and were restarted earlier than the entirety of Mannville. Approximately 185 bbl/d of higher cost heavy crude oil production remained shut-in at Mannville at year-end and is expected to be restored as heavy oil prices continue to improve.
- With capital investment shifted to the Clearwater play at Ukalta since mid-2019, Mannville heavy crude oil production represented 64% of total Company heavy crude oil sales volumes in 2020.
- Production and operating expenses for the base assets at Mannville in Eastern Alberta were down to $16.75/boe during the year (2019 – $17.17/boe), driven by the elimination of variable costs related to the shut-in of higher cost heavy crude oil production at Mannville and other cost mitigation initiatives.
- At the Mannville property, 17 (17.0 net) horizontal heavy crude oil wells are booked as undeveloped, down from 19 (19.0 net) at year end 2019. FDC of $21.6 million also includes recompletion of 22 conventional natural gas wells included in Perpetual's proved plus probable reserves.
- Total production and operating costs were down by $6.7 million (37%) over the prior year. Production and operating expenses were up 13% on a unit-of-production basis to $6.34/boe, compared to $5.59/boe for 2019, reflecting the increase in the Eastern Alberta production mix following the East Edson Transaction, which has higher operating costs compared to West Central. As production grows to approach infrastructure capacity at East Edson, and lower cost Clearwater production is brought online with drilling investment, unit operating costs are forecast to be restored to prior levels.
- In late April, the Government of Alberta announced its Site Rehabilitation Program ("SRP") aimed at incenting abandonment and reclamation activity. The SRP provides funding in the form of grant payments to the oil field services sector to abandon, and/or reclaim upstream oil and gas infrastructure with the objective to increase employment in this sector while managing end-of-life obligations for shut-in properties. Perpetual was well prepared to participate in the program to the greatest extent available to accelerate decommissioning activities, primarily in its Mannville property. Funding from the program provided $0.8 million for abandonment and reclamation projects in 2020, with an additional $1.3 million allocated for future work.
- Perpetual executed $1.0 million ($0.2 million net of SRP funding) of abandonment and reclamation projects in 2020, almost entirely at Mannville, to abandon 26 shut-in and inactive wells and advance reclamation. Thirteen reclamation certificates were received from the AER during the year, with nine additional certificates received subsequent to year-end. These decommissioning activities will serve to reduce future property tax and surface lease expenses.
- Perpetual's health and safety protocols were effective to manage the COVID-19 public health crisis with no significant disruptions. Field protocols were put in place to adhere to best practices set out by Canadian health authorities to diminish the risk of transmission. Corporate office employees worked from home for most of the second quarter and returned to a hybrid work environment in late June. Work at home protocols were reset in November in step with provincial guidelines.
- The Company continues to strive towards its triple zero target, recording one reportable spill, zero lost time injuries, and zero vehicle incidents in 2020, maintaining its exemplary environment, health and safety record. For the 2nd straight year, the Workers Compensation Board ranked Perpetual number 1 out of 265 peer companies in 2020.

Grow value and impact of the Clearwater play

- Capital investment in 2020 was focused on the Clearwater play in Eastern Alberta, where total spending of $5.5 million included costs to drill, complete and tie-in four (4.0 net) heavy crude oil wells in the Ukalta area. The new wells drilled in the first quarter of 2020 evaluated an oil-based mud system to reduce formation damage and improve wellbore inflow.
- In combination with the two (2.0 net) initial discovery wells drilled in the third quarter of 2019, the Ukalta Clearwater oil play was contributing approximately 730 bbl/d of production in mid-March prior to voluntary shut-ins driven by the collapse in global oil markets, representing close to 40% of the Company's total heavy oil sales volumes at that time.
- Ukalta production averaged 386 bbl/d in 2020 despite the shut-in of all six of the Company's Clearwater wells for much of the second quarter. Four wells were brought back online at the end of May, with the production re-start of the last two wells delayed to mid-July due to unseasonably wet weather which hampered lease and road construction work required for production operations on the newest lease.
- The drilling program successfully demonstrated enhanced capital efficiency and performance, de-risked additional development drilling inventory, and resulted in F&D costs of $9.26/boe (2019 – $17.27/boe) on a proved and probable basis, including changes in FDC. The new wells, combined with better than forecast well performance and farm-in arrangements, contributed to a 465% increase in Clearwater proved plus probable reserves of 2.7 million bbls, representing 10% of total Company reserves at December 31, 2020 (2019 – 1%).
- FDC in the Clearwater play increased $22.6 million year-over-year to $29.3 million on a proved plus probable basis. Increases are attributed to an increase in undeveloped locations booked in the Clearwater play, where 21 (21.0 net) multi-lateral horizontal heavy crude oil locations are booked as undeveloped, an increase from five (5.0 net) locations at year end 2019.
- Perpetual has identified 40 additional unbooked multi-lateral horizontal drilling locations at Ukalta within the same lower Clearwater sand target currently producing heavy crude oil in the six existing wells and where future performance is forecast to be similar to the wells drilled during the first quarter. An additional 54 unbooked horizontal multi-lateral drilling locations in two additional unproven zones have been identified on Perpetual-operated acreage, with varying degrees of risk, the potential of which will be evaluated over time.
- The Company secured additional acreage in 2020 along the Clearwater play trend in northeastern Alberta. Lands prospective for Clearwater exploration and development, including those to be earned through farm-in and option arrangements, now total 90 gross sections.
- Perpetual is well positioned to follow up the encouraging Clearwater results with profitable investment at WCS heavy crude oil prices exceeding $45.00/bbl.

Resolve the 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") (the "Sequoia Litigation") with respect to the Company's disposition of shallow conventional natural gas assets in Eastern Alberta to an unrelated third party on October 1, 2016 (the "Sequoia Disposition"). The decision dismissed and struck all claims against the Company's CEO and all but one of the claims filed by PricewaterhouseCoopers Inc. ("PwC") LIT 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 asset 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, challenging the entire decision, and Perpetual filed a similar notice of appeal contesting the BIA claim portion of the decision (the "First Appeal"). The First Appeal proceedings were heard on December 10, 2020.
- On February 25, 2020, Perpetual filed a second 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 asset transaction nor caused to be insolvent by the asset transaction. In July 2020, the Orphan Well Association ("OWA"), certain oil and gas companies, and six municipalities applied to intervene in the second BIA dismissal application proceedings. The OWA and certain oil and gas companies were permitted to intervene (the "Intervenors") in the proceedings which took place on October 1st and 2nd, 2020. The Intervenors were also permitted to intervene in the First Appeal proceedings.
- On January 14, 2021, the Court found that PwC could not establish a necessary element of the BIA claim as Sequoia was not insolvent at the time of, nor rendered insolvent by, the Sequoia Disposition. The Court therefore concluded that there is "no merit" to the BIA claim and it summarily dismissed the balance of the Statement of Claim. PwC has subsequently appealed the decision (the "Second Appeal").
- On January 25, 2021, the Court of Appeal issued their decision with respect to the First Appeal proceedings. The decision dismissed the appeal filed by Perpetual and granted certain aspects of the appeals filed by PwC, reinstating elements of the Sequoia Litigation for trial.
- Management expects that the Company is more likely than not to be completely 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 consolidated financial statements.

Advance technology-driven 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 negotiations with two parties for separate follow-on pilots in two different pools in Panny.
- The pilot projects are expected to be advanced during the winter of 2021/2022. Given the significant tenure on the bitumen leases at Panny, the Company will continue to investigate technology initiatives to advance understanding of the value potential of this material resource.
- In the fourth quarter of 2020, Perpetual entered into a Consulting and Opportunity Agreement with Carbonova Corp. ("Carbonova") as part of Perpetual's emerging Clean Hydrocarbon Economy strategy. The arrangement involves the provision of business and project management consulting services by Perpetual in exchange for common shares and a commercial development option to assist Carbonova as they advance their revolutionary proprietary process that utilizes carbon dioxide and methane, in combination with waste heat, to produce carbon nanofibers.
- Perpetual is a founding member of the Natural Gas Innovation Fund ("NGIF"), collaborating with industry partners across the natural gas value chain to help advance new technologies and research focused on continuous environmental performance improvements. Perpetual participated to fund four projects in 2020 to advance technology in the areas of methane emissions reduction, fuel-switching to cleaner burning natural gas, and conversion of natural gas into higher value products. Furthermore, Perpetual is participating with its partner, NGIF and the Canadian Emissions Reduction Innovation Network ("CERIN") to advance methane emissions reduction technology research using laser technology for remote monitoring and detection of both methane and other greenhouse gases at the Edson West Wolf gas plant.

YEAR-END 2020 RESERVES

Reserve Highlights

On a total Company basis, there was a 46% reduction in proved plus probable reserves year-over-year excluding production. The reduction associated with the East Edson Transaction was 45%, as East Edson represented 89% of total Company proved plus probable reserves at year-end 2019 and now represents 74% of proved plus probable reserves at year-end 2020. Strong performance of heavy crude oil and conventional natural gas wells in the Mannville property held reserves largely unchanged, excluding production. The Clearwater heavy crude oil play reserves increased by 495% in the proved plus probable reserve category and now represents 10% of total Company total proved plus probable reserves compared to 1% at year-end 2019. Perpetual's proved plus probable reserves at year-end 2020 are 35.4 MMboe, comprised of 28% heavy crude oil and NGL (2019 – 67.1 MMboe; 17% heavy crude 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 reserves were 25.0 MMboe at year-end 2020, representing 71% of the Company's proved plus probable reserves (2019 – 60%).
- Proved plus probable producing reserves were 12.4 MMboe at December 31, 2020, representing 35% of total proved plus probable reserves.
- The East Edson Transaction resulted in a large disposition adjustment of 29.8 MMboe. Further, the East Edson development plan has been revised to reflect longer extended-reach wells and reduced capital costs per well related to the operator's scale of operations as demonstrated by the execution of the 2020 drilling program, and increased well spacing, all contributing to increased capital efficiencies. Increased reserve recoveries per well have shifted a significant reserve volume from probable undeveloped to proved undeveloped, resulting in the positive technical revision in the proved category. Fewer overall probable locations now booked in East Edson resulted in a negative technical reserve revision in the probable category.
- Total proved plus probable reserves in the Clearwater play increased 495%. Drilling of four (4.0 net) wells in the Ukalta area resulted in additions of 1.6 MMboe. An additional 1.2 MMboe of proved plus probable undeveloped reserves is attributed to a farm-in agreement on three sections of development land.
- Total proved plus probable reserves in the Mannville district are largely unchanged, with a small decrease of 5% excluding production despite no capital spending in 2020 and price-related negative reserve revisions. Continued constructive waterflood performance resulted in positive technical reserve revisions as in past years.
- Exploration and development spending of $6.0 million in 2020 was largely focused on Clearwater projects. F&D costs related to the Clearwater play were $9.80/boe on a proved plus probable basis, including changes in FDC.
- Overall, FDC dropped to $112.5 million (2019 – $358.8 million) in the proved plus probable category, a reduction of $246.3 million. The difference is primarily at East Edson where FDC dropped $267.2 million to $61.4 million at year-end 2020, down from $328.6 million at December 31, 2019. The East Edson Transaction reduced the Company's interest in the East Edson property and its share of FDC to 50%, with a further reduction as a result of the carried interest funding of the associated eight (4.0 net) well drilling program. Furthermore, lower capital costs per well established by the operator, and a revised development plan with longer wells at wider spacing which results in fewer gross wells required for full development, combined for a positive impact on capital efficiencies to enhance the value of the East Edson property.

- 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 $187.8 million (2019 – $297.3 million). The decrease related primarily to the East Edson Transaction and the material decrease in the independent reserve evaluators' forecast for crude oil prices at year-end 2020 as compared to the prior year.

- All abandonment, decommissioning and reclamation obligations are included in the reserve report, consistent with year-end 2019. All reserve well decommissioning obligations as well as the additional costs expected to be incurred to abandon and reclaim non-reserve wells, facilities and pipelines are included.

- Based on the Consultant Average Price Forecast, Perpetual's reserve-based net asset value ("NAV") (discounted at 10%) at year-end 2020 is estimated at $98.8 million ($1.61 per share) as compared to $200.5 million ($3.27 per share) at year-end 2019.

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 & Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2020 (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 will be included in Perpetual's Annual Information Form ("AIF"), which, when filed, will be available on the Company's website at www.perpetualenergyinc.com and SEDAR at www.sedar.com.

Perpetual's reserves at December 31, 2020 are summarized below:

Working Interest Reserves at December 31, 2020[1]

	Light and Medium Crude Oil (*Mbbl*)	Heavy Oil (*Mbbl*)	Conventional Natural Gas (*MMcf*)	Natural Gas Liquids (*Mbbl*)	Oil Equivalent (*Mboe*)
Proved Producing	7	2,100	43,407	686	10,028
Proved Non-Producing	–	294	2,367	3	691
Proved Undeveloped	–	2,283	64,988	1,217	14,331
Total Proved	**7**	**4,676**	**110,762**	**1,906**	**25,050**
Probable Producing	2	531	10,175	166	2,395
Probable Non-Producing	–	63	4,584	41	868
Probable Undeveloped	–	2,095	27,058	519	7,123
Total Probable	**2**	**2,689**	**41,816**	**726**	**10,386**
Total Proved plus Probable	**9**	**7,365**	**152,579**	**2,633**	**35,436**

(1) May not add due to rounding.

Total proved reserves at December 31, 2020 account for 71% (2019 – 60%) of total proved plus probable reserves. Proved producing reserves of 10.0 MMboe comprise 40% (2019 – 40%) of total proved reserves. Proved plus probable producing reserves of 12.4 MMboe represent 35% (2019 – 30%) 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*)	2021	2022	2023	2024	2025	Remainder	Total
Eastern Alberta Shallow Gas	–	0.4	0.8	0.2	–	–	1.3
Mannville Heavy Oil	0.5	2.1	2.7	6.9	5.2	3.0	20.4
Clearwater	10.8	15.3	3.2	–	–	–	29.3
East Edson Wilrich	6.4	13.1	12.8	12.6	14.1	2.5	61.4
Total	**17.7**	**30.9**	**19.4**	**19.7**	**19.3**	**5.5**	**112.5**

(1) May not add due to rounding.

The McDaniel Report estimates that FDC of $112.5 million will be required over the life of the Company's proved plus probable reserves. Proved plus probable reserve forecast FDC have decreased by $246.3 million (69%) from $358.8 million at December 31, 2019.

The very significant reduction in FDC was driven by the East Edson Transaction, where FDC was reduced due to the sale of 50% of the Company's interest, and no capital being recorded for the remaining three wells of the eight well carried capital drilling program. Lower capital costs per well and fewer development wells in the revised development plan at East Edson further reduced FDC. FDC is attributable to the drilling, completion, equipping and tie-in of 32 (15.7 net) horizontal conventional natural gas wells targeting the Wilrich at East Edson, down from 66 (63.3 net) at year end 2019 due to the East Edson Transaction and the revised development plan requiring fewer developments wells due to increased well spacing and longer wells.

FDC in Eastern Alberta increased $20.9 million year-over-year to $51.1 million on a proved plus probable basis. Increases are attributed to an increase in undeveloped locations booked in the Clearwater play, where 21 (21.0 net) multi-lateral horizontal heavy crude oil locations are booked as undeveloped, an increase from 5 (5.0 net) locations at year end 2019. At the Mannville property, 17 (17.0 net) horizontal heavy crude oil wells are booked as undeveloped, down from 19 (19.0 net) at year end 2019. Future capital costs also include recompletion of 22 conventional natural gas wells included in Perpetual's proved plus probable reserves.

RESERVE LIFE INDEX

Perpetual's proved plus probable reserves to production ratio, also referred to as reserve life index ("RLI"), was 14.5 years at year-end 2020, while the proved RLI was 10.9 years, based upon the 2021 production estimates in the McDaniel Report. The following table summarizes Perpetual's historical calculated RLI.

Reserve Life Index(1)

Year-end	2020	2019	2018	2017	2016
Total Proved	10.9	13.4	13.1	9.1	9.3
Total Proved plus Probable	14.5	21.5	19.9	13.2	15.1

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

NET PRESENT VALUE OF RESERVES SUMMARY

Perpetual's heavy crude oil, conventional natural gas, and NGL reserves were evaluated by McDaniel using the Consultant Average Price Forecast effective January 1, 2021 and include the forecasted 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, 2021, assuming various discount rates:

NPV of Reserves, before income tax(1)(2)(3)

($ millions except as noted)	Undiscounted	5%	10%	15%	Discounted at 20%	Unit Value Discounted at 10%/Year (*$/boe*)(4)
Proved Producing	9	27	28	26	24	3.89
Proved Non-Producing	4	4	4	3	3	5.78
Proved Undeveloped	172	118	86	66	51	6.55
Total Proved	**185**	**149**	**117**	**95**	**78**	**5.62**
Probable Producing	31	22	17	13	11	7.72
Probable Non-Producing	5	3	2	2	1	3.08
Probable Undeveloped	120	75	51	37	29	7.96
Total Probable	**156**	**101**	**70**	**52**	**41**	**7.51**
Total Proved plus Probable	**341**	**250**	**188**	**147**	**119**	**6.21**

(1) January 1, 2021 Consultant Average price forecast
(2) Inclusive of the East Edson royalty and a further reduction for the retained East Edson royalty obligation by Perpetual through December 31, 2022 as part of the East Edson Transaction, asset retirement obligations for sites not assigned reserves, and corporate marketing obligations.
(3) May not add due to rounding.
(4) The unit values are based on net reserve volumes.

McDaniel's NPV10% estimate of Perpetual's total proved plus probable reserves at year-end 2020 was $188 million, down 37% from $297 million at year-end 2019. The decrease in NPV10% reflects the East Edson Transaction and the impact of lower commodity prices. These decreases were offset by reduced FDC in East Edson resulting from a more capital efficient development plan and an increase in value attributed to the Clearwater play including the drilling of four wells and the capture of additional lands that increased proved plus probable locations from five (5.0 net) at year-end 2019 to 21 (21.0 net) at year-end 2020. At a 10% discount factor, total proved reserves account for 63% (2019 – 59%) of the proved plus probable value. Proved plus probable producing reserves represent 24% (2019 – 34%) of the total proved plus probable value (discounted at 10%) as abandonment and reclamation obligations for non-producing wells, facilities and pipelines and forecast corporate marketing adjustments reduce the value of the developed producing reserves.

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. In West Central Alberta, 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	103,009	7.2	70.13
West Central	8,553	6.3	738.80
Oil Sands	96,000	6.0	62.66
Total	**207,562**	**19.6**	**94.23**

The fair market value of Perpetual's undeveloped land at year-end 2020, adjusted to remove the value of undeveloped lands with reserves assigned in West Central Alberta, is estimated by an external land consultant at $19.6 million, a decrease of 46% from $36.0 million relative to year-end 2019. The fair market value of undeveloped oil sands leases incorporates the depreciated value of 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 ("NAV")

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, 2020[(1)]

		Discounted at		
(*$ millions, except as noted*)	**Undiscounted**	**5%**	**10%**	**15%**
Total Proved plus Probable Reserves[(2)]	340.9	249.6	187.8	146.8
Fair market value of undeveloped lands[(3)]	19.6	19.6	19.6	19.6
Bank debt, net of working capital[(1)]	(24.6)	(24.6)	(24.6)	(24.6)
Term loan[(4)]	(46.8)	(46.8)	(46.8)	(46.8)
Senior notes[(4)]	(33.6)	(33.6)	(33.6)	(33.6)
Derivatives[(5)]	(3.6)	(3.6)	(3.6)	(3.6)
NAV	**251.9**	**160.6**	**98.8**	**57.8**
Common shares outstanding (*million*)	61.3	61.3	61.3	61.3
NAV per share (*$/share*)	**4.11**	**2.62**	**1.61**	**0.94**

(1) Financial information is per Perpetual's 2020 audited consolidated financial statements.
(2) Reserve values per McDaniel Report as at December 31, 2020. All abandonment obligations including future abandonment and reclamation costs for pipelines and facilities and non-reserve wells are included in the McDaniel Report.
(3) Independent third-party estimate; excludes undeveloped land in West Central Alberta with reserves assigned.
(4) Measured at principal amount.
(5) Fair value as at December 31, 2020, 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.

2020 F&D Costs[1]

(*$ millions except as noted*)		Proved		Proved & Probable
F&D Costs, including FDC				
Exploration and development capital expenditures[2]	$	5.98	$	5.98
Total change in FDC	$	7.62	$	(0.73)
Total F&D capital, including change in FDC	$	13.59	$	5.24
Reserve additions, including revisions (*MMboe*)		3.69		(1.18)
F&D Costs, including FDC (*$/boe*)	**$**	**3.68**	**$**	**(4.43)**
FD&A Costs, including FDC				
Exploration and development capital expenditures[2]	$	5.98	$	5.98
Proceeds on dispositions, net of acquisitions	$	(34.53)	$	(34.53)
Total change in FDC	$	(108.32)	$	(246.30)
Total FD&A capital, including change in FDC	$	(136.88)	$	(274.86)
Reserve additions, including net acquisitions (*MMboe*)		(13.42)		(29.79)
FD&A Costs, including FDC (*$/boe*)	**$**	**10.20**	**$**	**9.23**

(1) Financial information is per Perpetual's 2020 audited consolidated financial statements.
(2) Excludes corporate assets and expenditures on decommissioning obligations.

2021 OUTLOOK

Production at Perpetual's non-operated West Central properties is expected to increase 25% to 30% from fourth quarter levels to 3,800 to 4,000 boe/d in the first quarter of 2021 (Q4 2020 – 3,033 boe/d). Production continues to ramp up at East Edson as new carried interest wells come onstream, with two (1.0 net) additional carried interest wells commencing production in March 2021. The Purchaser is anticipated to complete its eight well carried interest drilling commitment by the end of the third quarter of 2021.

Total abandonment and reclamation expenditures of up to $2.2 million are forecast in 2021, with up to $1.3 million to be funded through Alberta's Site Rehabilitation Program.

Perpetual's reserve-based credit facility matures on April 30, 2021 and its Term Loan matures on May 14, 2021. To preserve liquidity, the Company will defer further capital spending until the Credit Facility Borrowing Limit redetermination has been completed and the Term Loan has been refinanced or maturity extended. The Company will issue its 2021 Outlook once the refinancing activities are complete and capital spending plans have been approved by the Board of Directors.

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, 2020 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, 2020 and 2019. The Corporation's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") which require publicly accountable enterprises to prepare their financial statements using International Financial Reporting Standards ("IFRS"). Readers are referred to the advisories for additional information regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information and Statements" section of this MD&A. The date of this MD&A is February 24, 2021.

NATURE OF BUSINESS: Perpetual is an oil and natural gas exploration, production and marketing company headquartered in Calgary, Alberta. Perpetual owns a diversified asset portfolio, including liquids-rich conventional natural gas assets in the deep basin of West Central Alberta, heavy crude oil and shallow conventional natural gas in Eastern Alberta, and undeveloped bitumen 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", "net working capital deficiency", "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: 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 added back non-cash oil and natural gas revenue in-kind, equal to retained East Edson royalty obligation payments taken in-kind, to present the equivalent amount of cash revenue generated. 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 (used in) operating activities. 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 per share is calculated using the 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*)	**2020**	2019	**2020**	2019
Net cash flows from (used in) operating activities	**(1,104)**	(1,290)	**(9,533)**	17,806
Change in non-cash working capital	**1,479**	705	**(1,015)**	(4,602)
Decommissioning obligations settled	**95**	540	**210**	1,733
Oil and natural gas revenue in-kind	**917**	–	**2,319**	–
Payments of gas over bitumen royalty financing	**(197)**	(225)	**(704)**	(1,013)
Payments of restructuring costs	**50**	610	**936**	610
Adjusted funds flow	**1,240**	340	**(7,787)**	14,534
Adjusted funds flow per share	**0.02**	0.01	**(0.13)**	0.24
Adjusted funds flow per boe	**2.85**	0.46	**(4.25)**	4.43

Available Liquidity: Available Liquidity is defined as Perpetual's reserve-based credit facility (the "Credit Facility") borrowing limit (the "Borrowing Limit"), less borrowings and letters of credit issued under the Credit Facility. 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, **2020**	2019	Years ended December 31, **2020**	2019
Royalties	**1,831**	3,383	**6,571**	11,260
Production and operating	**3,014**	3,839	**11,634**	18,332
Transportation	**804**	1,551	**3,617**	6,258
General and administrative	**1,994**	2,406	**7,870**	11,660
Cash finance expense	**155**	2,376	**6,587**	9,280
Cash costs	**7,798**	13,555	**36,279**	56,790
Cash costs per boe	**17.92**	18.44	**19.78**	17.31

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. Realized revenue is used by management to calculate the Corporation's net realized commodity prices, taking into account the 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 price.

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 in 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: Net working capital deficiency includes total current assets and current liabilities excluding short-term derivative assets and liabilities related to the Corporation's risk management activities, Tourmaline Oil Corp. ("TOU") share investment, TOU share margin demand loan, revolving bank debt, second lien term loan (the "Term Loan"), current portion of royalty obligations, 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. Net debt includes the carrying value of net bank debt, the principal amount of the Term Loan, the principal amount of the TOU share margin demand loan and the principal amount of senior notes, reduced for the mark-to-market value of the TOU share investment. Net 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.

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 conventional 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 conventional natural gas and heavy crude oil, based on the current prices of natural gas and crude oil, differ significantly from the energy equivalency of 6 Mcf:1 bbl. A conversion ratio of 1 bbl of heavy crude oil to 1 bbl of NGL has also been used throughout this MD&A. Refer to the "Production" section of this MD&A for details of constituent product components that comprise Perpetual's boe production.

FOURTH QUARTER 2020 HIGHLIGHTS

Fourth quarter production averaged 4,730 boe/d, down 41% from the comparative period of 2019 (Q4 2019 – 7,991 boe/d). The decrease in production was due to the sale of a 50% working interest in the East Edson property in West Central Alberta to a third-party (the "Purchaser") for consideration including a cash payment of $35 million and the carried interest funding of the drill, complete and tie-in costs for an eight well drilling program (the "East Edson Transaction"). The closing of the East Edson Transaction on April 1, 2020 reduced West Central production by 3,220 boe/d when compared to the fourth quarter of 2019. Compared to the third quarter of 2020, total production increased by 13% or 542 boe/d, as production from the first five (2.5 net) East Edson carried interest wells is now online. In addition, the Company continued to reactivate heavy crude oil production as oil prices recover and stabilize. As of December 31, 2020, Perpetual had restarted all heavy crude oil production with the exception of approximately 185 bbl/d of higher cost production from certain wells at Mannville. Drilling of two (1.0 net) additional East Edson carried interest wells commenced in late January 2021 and are forecast to be on production by the end of March 2021. The final carried interest well is expected to be drilled and on production in the third quarter of 2021.

Realized revenue was $21.73/boe in the fourth quarter of 2020, 11% higher than the comparative period of 2019 (Q4 2019 – $19.50/boe). The increase was due primarily to the 20% improvement in Perpetual's realized oil price to $52.60/bbl, bolstered by financial hedging gains of $2.2 million ($18.92/boe). Compared to the prior year period, realized natural gas prices of $1.46/Mcf were 27% lower, due to realized hedging losses on locked-in AECO-NYMEX basis differential contracts of $2.6 million ($1.46/Mcf) despite the 6% increase in both NYMEX and AECO reference prices over the same period. In the fourth quarter of 2020, the Company reduced its fixed volume obligations under its market diversification contract by 14,600 MMBtu/d for the period commencing November 1, 2021 and ending on October 31, 2022 to align conventional natural gas sales obligations with lower forecast production volumes following the East Edson Transaction. The modification resulted in a realized gain on derivatives of $0.5 million ($1.15/boe) and increased the Company's realized natural gas price by $0.28/Mcf in the fourth quarter of 2020. Compared to the third quarter of 2020, realized revenue of $21.73/boe was up 21% (Q3 2020 – $17.93/boe), reflecting the 13% quarter-over-quarter increase in production combined with higher realized natural gas and NGL prices, partially offset by lower realized heavy crude oil prices.

Cash costs were down 3% on a unit-of-production basis to $17.92/boe (Q4 2019 - $18.44/boe). On an absolute dollar basis, cash costs were $7.8 million, 42% lower than the prior year period (Q4 2019 – $13.6 million) due to the East Edson Transaction, the reduction in work hours and corresponding employee compensation to 80% effective April 1, 2020, and payments received from the Canada Emergency Wage Subsidy

("CEWS") and Canada Emergency Rent Subsidy ("CERS") of $0.3 million. In addition, the semi-annual interest payment of $1.8 million that was payable December 31, 2020, was deferred by the Company's Term Loan lender and added to the principal amount owing as a condition of the Credit Facility lenders agreeing to extend the Credit Facility maturity to March 1, 2021.

Net income for the fourth quarter of 2020 was $14.4 million ($0.24/share), up $46.9 million from the prior year period (Q4 2019 – net loss of $32.5 million and $0.54/share). The increase was due primarily to the non-cash impairment reversal of $18.0 million recognized in the fourth quarter of 2020, compared to an impairment charge of $24.5 million in the fourth quarter of 2019. In addition, the change in fair value of derivatives contributed $0.4 million to net income in the fourth quarter of 2020, $5.3 million higher than the prior year period (Q4 2019 – loss of $4.9 million).

Net cash flows used in operating activities were $1.1 million, comparable to the prior year period of $1.3 million. Changes in non-cash working capital reduced operating cash flows by $1.5 million in the fourth quarter of 2020 compared to a reduction of $0.7 million in the comparative period of 2019. Excluding changes in non-cash working capital, net cash flows from operating activities were $0.4 million, an increase of $1.0 million from the prior year period, due primarily to the deferral of $1.8 million of Term Loan interest, partially offset by the 41% decrease in production.

Adjusted funds flow in the fourth quarter of 2020 was $1.2 million ($0.02/share), $0.9 million higher than the prior year period (Q4 2019 – $0.3 million). The increase was due to the same factors that drove higher cash flows from operating activities before changes in non-cash working capital. Compared to the third quarter of 2020, adjusted funds flow improved by $3.3 million, due to the deferral of $1.8 million of Term Loan interest, combined with the 13% increase in production and significantly higher realized natural gas prices of $1.46/Mcf (Q3 2020 – $0.06/Mcf).

2020 ANNUAL HIGHLIGHTS

Exploration and development spending in 2020 was $6.0 million, down 54% from the prior year (2019 – $12.9 million). Capital investment was focused on the Clearwater play in Eastern Alberta, where total spending of $5.5 million included costs to drill, complete and tie-in four (4.0 net) heavy crude oil wells in the Ukalta area. The program successfully demonstrated enhanced capital efficiency and performance, de-risked additional development drilling inventory, and resulted in finding and development costs ("F&D") of $9.26/boe (2019 – $17.27/boe) on a proved and probable basis, including changes in future development capital ("FDC"). The Clearwater drilling program, combined with better than forecast well performance and farm-in arrangements, contributed to a year-over-year increase in Clearwater proved plus probable reserves of 2.7 million bbls, representing 10% of total Company reserves at December 31, 2020 (2019 – 1%).

In accordance with the terms of the East Edson Transaction, the Purchaser drilled, completed and tied-in five (2.5 net) horizontal Wilrich carried interest wells during the year at the 50% owned East Edson property, with the next two (1.0 net) wells forecast to be on production by the end of March 2021. The final carried interest well is scheduled to be drilled, completed and tied-in during the third quarter of 2021. The East Edson development plan has been revised to reflect increased well spacing, longer extended-reach wells, and reduced capital costs per well related to the Purchaser's scale of operations as demonstrated by the execution of the 2020 carried interest drilling program. After giving effect to the East Edson Transaction, East Edson FDC decreased by 63% or $102.9 million on a proved plus probable basis, while proved reserves have increased by 8% from prior year levels.

Production in 2020 averaged 5,012 boe/d (29% heavy crude oil and NGL), a decrease of 44% from 8,988 boe/d (22% heavy crude oil and NGL) in 2019. The decrease in production was due primarily to the closing of the East Edson Transaction, combined with the temporary shut-in of heavy crude oil production throughout the second quarter in response to the abrupt drop in oil prices experienced due to local and global supply and demand imbalances and the COVID-19 pandemic. As Western Canadian Select ("WCS") prices improved from their April lows, the Company began reactivating certain low-cost heavy crude oil production in mid-May 2020, and has continued to ramp up production as oil prices improve. Approximately 185 bbl/d of higher cost heavy crude oil production remains shut-in at Mannville.

Realized revenue was $30.2 million in 2020, down $43.4 million (59%) from $73.6 million in 2019 due to the combined effect of the 44% decrease in annual production and lower realized revenue per boe. On a unit-of-production basis, realized revenue was $16.46/boe, 27% lower than the prior year period (2019 – $22.43/boe) and due primarily to lower realized natural gas and NGL prices of 69% and 23%, respectively. Compared to the AECO Daily Index price of $2.23/Mcf, realized natural gas prices were negatively impacted by physical and financial hedging losses of $12.0 million ($1.53/Mcf) which were primarily related to AECO-NYMEX basis differentials, and included a net loss of $0.5 million ($0.06/Mcf) related to modifications made to the natural gas market diversification contract. Market diversification contract revenue further reduced the realized natural gas price by $0.7 million or $0.09/Mcf in 2020, compared to an increase of $0.64/Mcf in 2019. For the year ended December 31, 2020, Perpetual's realized oil price was $49.37/bbl, up 10% from $44.87/bbl in 2019. Realized oil prices were improved by $19.05/bbl associated with realized hedging gains during the year (2019 – realized losses of $8.74/bbl).

Cash costs were $36.3 million in 2020, down $20.5 million (36%) from 2019. The decrease was due primarily to lower royalties, production and operating expenses and transportation costs associated with the 44% decrease in production, combined with lower general and administrative expense driven by a 25% reduction in Perpetual's corporate employee head count that was implemented late in the third quarter of 2019, along with the reduction in work hours and corresponding employee compensation to 80%, effective April 1, 2020. In 2020, the Company received total payments of $1.3 million from the CEWS and CERS programs which were recognized as a reduction to general and administrative and production and operating expenses of $1.0 million and $0.3 million, respectively (2019 – nil). The deferral of Term Loan interest also reduced cash finance expense by $1.8 million during the year.

The net loss for 2020 was $61.6 million ($1.01/share), down from $94.0 million in 2019 ($1.56/share). The net loss in 2020 was impacted by aggregate non-cash impairment charges of $42.5 million (2019 – $47.1 million), comprised of $60.5 million of impairment charges booked at March 31, 2020, partially offset by an $18.0 million impairment reversal recorded at December 31, 2020. The net loss also included an unrealized loss of $0.9 million related to the change in fair value of the TOU share investment (2019 – $3.2 million) which was sold in the first quarter of 2020.

Net cash flows used in operating activities were $9.5 million in 2020, down $27.3 million compared to cash flows from operating activities of $17.8 million in 2019. The decrease was due primarily to the $43.4 million reduction in realized revenue, partially offset by a $20.5 million reduction in cash costs.

For the year ended December 31, 2020, adjusted funds flow was negative $7.8 million ($0.13/share), down $22.3 million from $14.5 million ($0.24/share) in 2019 as the impact of the 44% year-over-year decrease in production combined with lower natural gas and NGL prices outweighed the 36% decrease in cash costs.

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 share investment for net cash proceeds of $14.3 million. Net proceeds were used to repay the outstanding TOU share margin demand loan of $0.1 million, with the balance applied to the Credit Facility. On April 1, 2020, the Company closed the East Edson Transaction. Net proceeds of $34.8 million were used to repay a portion of the Credit Facility. Effective April 1, 2020, Perpetual's syndicate of Credit Facility lenders completed their borrowing base redetermination, incorporating the impact of the East Edson Transaction. The Borrowing Limit was reduced from $45 million to $20 million. As at December 31, 2020, $17.5 million was borrowed and $0.9 million of letters of credit were issued on the Credit Facility. The next Borrowing Limit redetermination is scheduled on or prior to March 1, 2021. If not extended by March 1, 2021, the Credit Facility will cease to revolve, and all outstanding advances will be repayable. The semi-annual interest payment of $1.8 million that was payable December 31, 2020, was deferred by the Company's Term Loan lender and added to the principal amount owing as a condition of the Credit Facility lenders agreeing to extend the Credit Facility maturity to March 1, 2021. The further 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 and deferred interest that matures and requires repayment on March 14, 2021. The Company remains dependent on the continued support of its lenders to extend approaching maturities.

During the year ended December 31, 2020, there was a dramatic decline in oil, natural gas, and NGL commodity prices due to local and global supply and demand imbalances and the COVID-19 pandemic. This contributed to a net working capital deficiency of $7.1 million as at December 31, 2020 and a $9.5 million use of cash from operations for the year then ended. The Company will require additional financing to fund the working capital deficiency and future operations, and to refinance the upcoming Credit Facility and Term Loan maturities as the available liquidity and operating cash flows are not anticipated to be sufficient. In January 2021, the Company exchanged it's $33.6 million 8.75% unsecured senior notes due January 23, 2022 for new $33.6 million 8.75% third lien senior notes due January 23, 2025 (the "2025 Senior Notes"). Interest on the 2025 Senior Notes may be paid in-kind at the option of the Company by adding the interest payment to the principal amount owing. On January 23, 2021, the $1.5 million semi-annual interest payment on the 2025 Senior Notes was paid in-kind. Although cash flows from operations are forecast to improve for the next twelve-month period, Perpetual is considering other options including the extension of existing debt maturity dates, alternative financing, and the sale or monetization of additional assets.

Due to the facts and circumstances detailed above, coupled with considerable economic instability and uncertainty in the oil and gas industry 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 the Company's ability to manage its capital structure. As a result, there is 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 meet its obligations as they come due. Therefore, the Company may be unable to realize its assets and discharge its liabilities in the normal course of business.

Perpetual's 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.

SEQUOIA LITIGATION UPDATE

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") (the "Sequoia Litigation") with respect to the Company's disposition of shallow conventional natural gas assets in Eastern Alberta to an unrelated third party on October 1, 2016 (the "Sequoia Disposition"). The decision dismissed and struck all claims against the Company's CEO and all but one of the claims filed by PricewaterhouseCoopers Inc. ("PwC") LIT 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 asset 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, challenging the entire decision, and Perpetual filed a similar notice of appeal contesting the BIA claim portion of the decision (the "First Appeal"). The First Appeal proceedings were heard on December 10, 2020.

On February 25, 2020, Perpetual filed a second 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 asset transaction nor caused to be insolvent by the asset transaction. In July 2020, the Orphan Well Association ("OWA"), certain oil and gas companies, and six municipalities applied to intervene in the second BIA dismissal application proceedings. The OWA and certain oil and gas companies were permitted to intervene (the "Intervenors") in the proceedings which took place on October 1st and 2nd, 2020. The Intervenors were also permitted to intervene in the First Appeal proceedings.

On January 14, 2021, the Court found that PwC could not establish a necessary element of the BIA claim as Sequoia was not insolvent at the time of, nor rendered insolvent by, the Sequoia Disposition. The Court therefore concluded that there is "no merit" to the BIA claim and it summarily dismissed the balance of the Statement of Claim. PwC has subsequently appealed the decision (the "Second Appeal").

On January 25, 2021, the Court of Appeal issued their decision with respect to the First Appeal proceedings. The decision dismissed the appeal filed by Perpetual and granted certain aspects of the appeals filed by PwC, reinstating certain elements of the Sequoia Litigation for trial.

Management expects that the Company is more likely than not to be completely 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 consolidated financial statements.

2021 OUTLOOK

Perpetual's reserve-based credit facility is currently undergoing its borrowing limit redetermination, which is scheduled to be completed on or prior to March 1, 2021 and its Term Loan matures on March 14, 2021. To preserve liquidity, the Company will defer further capital spending until the credit facility borrowing limit redetermination has been completed and the Term Loan has been refinanced or maturity extended. The Company will issue its 2021 Outlook once the borrowing limit redetermination is known and capital spending plans have been approved by the Board of Directors.

Production at Perpetual's non-operated West Central properties is expected to increase 25% to 30% from fourth quarter levels to 3,800 to 4,000 boe/d in the first quarter of 2021 (Q4 2020 – 3,033 boe/d). Production continues to ramp up at East Edson as new carried interest wells come onstream, with two (1.0 net) additional carried interest wells forecast to be on production by the end of March 2021. The Purchaser is anticipated to complete its eight well carried interest drilling commitment by the end of the third quarter of 2021.

Total abandonment and reclamation expenditures of up to $2.2 million are forecast in 2021, with up to $1.3 million to be funded through Alberta's Site Rehabilitation Program ("SRP").

2020 FOURTH QUARTER AND ANNUAL CAPITAL EXPENDITURES

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2020**	2019	**2020**	2019
Exploration and development	**464**	1,983	**5,975**	12,865
Corporate assets	**2**	12	**(36)**	74
Capital expenditures	**466**	1,995	**5,939**	12,939
Acquisitions	**–**	–	**222**	–
Proceeds from dispositions of oil and gas properties	**–**	–	**(34,750)**	–
Net capital expenditures	**466**	1,995	**(28,589)**	12,939

Exploration and development spending by area

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2020**	2019	**2020**	2019
West Central	**441**	12	**476**	1,185
Eastern Alberta	**23**	1,971	**5,499**	11,680
Total	**464**	1,983	**5,975**	12,865

Wells drilled by area

	Three months ended December 31,		Years ended December 31,	
(gross/net)	**2020**	2019	**2020**	2019
West Central	**3/1.5**	–/–	**5/2.5**	–/–
Eastern Alberta	**–/–**	–/–	**4/4.0**	5/5.0(1)
Total	**3/1.5**	–/–	**9/6.5**	5/5.0(1)

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

Perpetual's exploration and development spending in the fourth quarter of 2020 was $0.5 million and was focused on maintenance projects at the East Edson property in West Central. Compared to the prior year period, expenditures decreased by 77% (Q4 2019 – $2.0 million). At the 50% owned East Edson property, three (1.5 net) horizontal Wilrich wells were drilled and tied-in to production during the fourth quarter pursuant to the Purchaser's carried interest drilling commitment, with the next two (1.0 net) wells forecast to be on production by the end of March 2021. Fourth quarter spending in Eastern Alberta was nominal, consistent with guidance released on November 10, 2020.

For the year ended December 31, 2020, exploration and development spending was $6.0 million, down 54% from 2019. This spending excludes the five (2.5 net) carried interest wells drilled at East Edson. The carried interest drilling program has confirmed a $102.9 million (63%) reduction in future development capital on the remaining 50% working interest at East Edson, reflecting the revised development plan which includes increased well spacing, longer extended-reach wells, and reduced capital costs per well related to the Purchaser's scale of operations as demonstrated by the execution of the 2020 drilling program. Spending in Eastern Alberta was $5.5 million, where four (4.0 net) multi-lateral heavy crude oil wells were drilled, completed and tied-in at Ukalta targeting the Clearwater formation, resulting in area F&D costs of $9.26/boe, including changes in FDC.

Acquisitions and Dispositions

On April 1, 2020, the Company sold a 50% working interest in its East Edson property in West Central Alberta. The consideration received, and calculation of the gain (loss) recorded on disposition is summarized below:

($ thousands)	
Cash proceeds from disposition (a)	**34,750**
Drilling program rights received (b)	**18,000**
Retained East Edson royalty obligation (c)	**(6,996)**
Carrying amount of assets disposed (d)	**(52,803)**
Carrying amount of decommissioning obligations disposed (e)	**7,049**
Gain (loss) on disposition	**–**

a)	Cash proceeds from disposition	$35.0 million of cash received on closing, net of $0.2 million of transaction costs and closing adjustments. In order to reflect the nature of the proceeds received, cash proceeds from disposition have been allocated on the consolidated statements of cash flows to financing and investing activities in the amount of $7.0 million and $27.8 million, respectively.
b)	Drilling program rights received	$18.0 million of drilling program rights, comprised of the carried interest funding of the drill, complete, and tie-in costs for an eight-well drilling program. Five (2.5 net) horizontal wells targeting development of the Wilrich formation were drilled, completed and commenced production during the second half of 2020. The Purchaser is required to fulfill its entire commitment by April 1, 2022 and will be obligated to pay Perpetual $2.25 million for each commitment well not completed and having commenced production by this time.
c)	Retained East Edson royalty obligation	$7.0 million that Perpetual will retain until December 31, 2022 on behalf of the Purchaser, comprising the fair value of the Purchaser's 50% working interest in the existing gross overriding royalty on the East Edson property equivalent to 2.8 MMcf/d of conventional natural gas and associated NGL production. This obligation has been recorded in the consolidated statement of financial position under the heading "Royalty obligations".
d)	Carrying amount of assets disposed	$52.8 million of oil and gas properties ($50.4 million) and exploration and evaluation assets ($2.4 million).
e)	Carrying amount of decommissioning obligations disposed	$7.0 million of decommissioning obligations associated with oil and gas properties disposed.

Expenditures on decommissioning obligations

During the fourth quarter of 2020, Perpetual executed $0.9 million (Q4 2019 – $0.5 million) of abandonment and reclamation projects, of which $0.8 million was funded by Alberta's Site Rehabilitation Program ("SRP"). SRP funding is presented on the consolidated statements of loss and comprehensive loss as "other income". As part of Perpetual's focus on well and pipeline abandonment and reclamation, two reclamation certificates were received from the Alberta Energy Regulator ("AER") during the fourth quarter of 2020 (Q4 2019 – four reclamation certificates) which will result in the cessation of associated property tax and surface lease expenses. For the year ended December 31, 2020, Perpetual executed $1.0 million (2019 – $1.7 million) of abandonment and reclamation projects and received 13 reclamation certificates. Subsequent to year end, the Company has received six additional reclamation certificates related to projects completed in 2020. Total abandonment and reclamation expenditures of up to $2.2 million are forecast in 2021, with up to $1.3 million to be funded through the SRP.

SUMMARY OF QUARTERLY AND ANNUAL NET INCOME (LOSS)

Three months ended December 31,

	2020		2019	
	(*$ thousands*)	**(*$/boe*)**	(*$ thousands*)	(*$/boe*)
Realized revenue[(1)]	**9,456**	**21.73**	14,335	19.50
Royalties	**(1,831)**	**(4.21)**	(3,383)	(4.60)
Production and operating expenses	**(3,014)**	**(6.93)**	(3,839)	(5.22)
Transportation costs	**(804)**	**(1.85)**	(1,551)	(2.11)
Operating netback[(1)]	**3,807**	**8.74**	5,562	7.57
Unrealized change in fair value of derivatives	**(825)**	**(1.90)**	(3,369)	(4.58)
Gas over bitumen royalty credit	**211**	**0.48**	202	0.27
Other income	**812**	**1.87**	–	–
Exploration and evaluation	**(483)**	**(1.11)**	(811)	(1.10)
General and administrative	**(1,994)**	**(4.58)**	(2,406)	(3.27)
Share-based payments	**(517)**	**(1.19)**	(488)	(0.66)
Depletion and depreciation	**(2,906)**	**(6.68)**	(6,960)	(9.47)
Impairment reversal (impairment)	**18,000**	**41.36**	(24,452)	(33.26)
Finance expense	**(1,662)**	**(3.82)**	(2,981)	(4.05)
Change in fair value of TOU share investment	**–**	**–**	3,205	4.36
Net income (loss)	**14,443**	**33.17**	(32,498)	(44.19)
Net income (loss) per share - basic	**0.24**		(0.54)	

Years ended December 31,

	2020		2019	
	(*$ thousands*)	**(*$/boe*)**	(*$ thousands*)	(*$/boe*)
Realized revenue[(1)]	**30,194**	**16.46**	73,572	22.43
Royalties	**(6,571)**	**(3.58)**	(11,260)	(3.43)
Production and operating expenses	**(11,634)**	**(6.34)**	(18,332)	(5.59)
Transportation costs	**(3,617)**	**(1.97)**	(6,258)	(1.91)
Operating netback[(1)]	**8,372**	**4.57**	37,722	11.50
Unrealized change in fair value of derivatives	**9,901**	**5.40**	(21,893)	(6.67)
Gas over bitumen royalty credit	**685**	**0.37**	852	0.26
Other income	**812**	**0.44**	–	–
Exploration and evaluation	**(712)**	**(0.39)**	(1,797)	(0.55)
General and administrative	**(7,870)**	**(4.29)**	(11,660)	(3.55)
Share-based payments	**(2,017)**	**(1.10)**	(2,295)	(0.70)
Depletion and depreciation	**(15,533)**	**(8.47)**	(31,188)	(9.51)
Impairment, net of reversals	**(42,500)**	**(23.17)**	(47,052)	(14.34)
Finance expense	**(11,831)**	**(6.45)**	(11,951)	(3.64)
Change in fair value of TOU share investment	**(904)**	**(0.49)**	(3,207)	(0.98)
Restructuring costs	**–**	**–**	(1,546)	(0.47)
Net loss	**(61,597)**	**(33.58)**	(94,015)	(28.65)
Net loss per share - basic	**(1.01)**		(1.56)	

(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, 2020 and 2019:

	Three months ended December 31, 2020			Three months ended December 31, 2019		
(*$ thousands*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Petroleum and natural gas ("P&NG") revenue[1]	**3,878**	**4,300**	**8,178**	9,366	6,464	15,830
Realized gains (losses) on derivatives[2][3]	**–**	**–**	**1,278**	–	–	(1,495)
Royalties	**(1,241)**	**(590)**	**(1,831)**	(2,584)	(799)	(3,383)
Production and operating expenses	**(1,044)**	**(1,970)**	**(3,014)**	(1,698)	(2,141)	(3,839)
Transportation costs	**(339)**	**(465)**	**(804)**	(944)	(607)	(1,551)
Operating netback	**1,254**	**1,275**	**3,807**	4,140	2,917	5,562

	Year ended December 31, 2020			Year ended December 31, 2019		
(*$ thousands*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Petroleum and natural gas revenue[1]	**15,918**	**13,568**	**29,486**	47,199	27,162	74,361
Realized gains (losses) on derivatives[2][3]	**–**	**–**	**708**	–	–	(789)
Royalties	**(5,030)**	**(1,541)**	**(6,571)**	(7,833)	(3,427)	(11,260)
Production and operating expenses	**(4,408)**	**(7,226)**	**(11,634)**	(7,188)	(11,144)	(18,332)
Transportation costs	**(2,055)**	**(1,562)**	**(3,617)**	(4,176)	(2,082)	(6,258)
Operating netback	**4,425**	**3,239**	**8,372**	28,002	10,509	37,722

	Three months ended December 31, 2020			Three months ended December 31, 2019		
(*$/boe*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**3,033**	**1,697**	**4,730**	6,253	1,738	7,991
Petroleum and natural gas revenue[1]	**13.90**	**27.55**	**18.79**	16.28	40.43	21.53
Realized gains (losses) on derivatives[2][3]	**–**	**–**	**2.94**	–	–	(2.03)
Royalties	**(4.45)**	**(3.78)**	**(4.21)**	(4.49)	(5.00)	(4.60)
Production and operating expenses	**(3.74)**	**(12.62)**	**(6.93)**	(2.95)	(13.39)	(5.22)
Transportation costs	**(1.21)**	**(2.98)**	**(1.85)**	(1.64)	(3.80)	(2.11)
Operating netback	**4.50**	**8.17**	**8.74**	7.20	18.24	7.57

	Year ended December 31, 2020			Year ended December 31, 2019		
(*$/boe*)	**West Central**	**Eastern**	**Total**	West Central	Eastern	Total
Operating netback per boe						
Production (*boe/d*)	**3,525**	**1,487**	**5,012**	7,176	1,812	8,988
Petroleum and natural gas revenue[1]	**12.34**	**24.92**	**16.07**	18.02	41.06	22.67
Realized gains (losses) on derivatives[2][3]	**–**	**–**	**0.39**	–	–	(0.24)
Royalties	**(3.90)**	**(2.83)**	**(3.58)**	(2.99)	(5.18)	(3.43)
Production and operating expenses	**(3.42)**	**(13.27)**	**(6.34)**	(2.74)	(16.84)	(5.59)
Transportation costs	**(1.59)**	**(2.87)**	**(1.97)**	(1.59)	(3.15)	(1.91)
Operating netback	**3.43**	**5.95**	**4.57**	10.70	15.89	11.50

(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 and losses 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.

(3) For the fourth quarter of 2020, realized gains on derivatives include $0.5 million ($1.15/boe) of gains from the modification of the market diversification contract for the November 1, 2021 to October 31, 2022 period. For the year ended December 31, 2020, realized gains on derivatives include a net loss of $0.5 million ($0.26/boe) from the modification of the market diversification contract for the November 1, 2020 to October 31, 2022 period.

For the fourth quarter of 2020, Perpetual's operating netback was $3.8 million ($8.74/boe), down 32% from $5.6 million ($7.57/boe) in the comparative period of 2019. This decrease was driven primarily by the 41% drop in production compared to the prior year period, partially offset by lower costs. The significant decrease in production was the result of the East Edson Transaction which closed on April 1, 2020, combined with natural declines resulting from limited capital investment. For the fourth quarter of 2020, the Company's operating netback included $1.3 million in realized gains on financial derivatives (Q4 2019 – realized losses of $1.5 million), comprised of $2.2 million of gains from oil contracts, partially offset by losses of $0.9 million on financial natural gas contracts. In the fourth quarter of 2020, the Company reduced its fixed volume obligations under its natural gas market diversification contract by 14,600 MMBtu/d for the period commencing November 1, 2021 and ending on October 31, 2022 to align conventional natural gas sales obligations with lower forecast production volumes following the East Edson Transaction. The modification resulted in a realized gain on derivatives of $0.5 million ($1.15/boe) and increased the Company's realized natural gas price by $0.28/Mcf in the fourth quarter of 2020.

For the year ended December 31, 2020, Perpetual's operating netback was $8.4 million ($4.57/boe), down 78% from $37.7 million ($11.50/boe) in 2019. The decrease was due to a 44% decline in year-over-year production, combined with the 60% decrease in operating netback per boe, which was the result of lower realized natural gas and NGL prices of 69% and 23% respectively, combined with higher costs per boe. For the year ended December 31, 2020, the Company's operating netback included $0.7 million in net realized gains on financial derivatives (2019 – realized losses of $0.8 million), comprised of $7.5 million of gains from oil contracts, partially offset by losses of $6.8 million from financial natural gas and NGL contracts.

Production

	Three months ended December 31,		Years ended December 31,	
	2020	2019	**2020**	2019
Conventional natural gas (*MMcf/d*)				
Eastern Alberta	**2.7**	2.8	**2.5**	3.6
West Central	**16.8**	33.8	**19.0**	38.7
Total conventional natural gas(1)	**19.5**	36.6	**21.5**	42.3
Heavy crude oil (*bbl/d*)				
Eastern Alberta(2)	**1,240**	1,264	**1,076**	1,216
West Central	**1**	11	**6**	8
Total heavy crude oil	**1,241**	1,275	**1,082**	1,224
Total NGL (*bbl/d*)(3)	**237**	606	**346**	719
Total production (*boe/d*)	**4,730**	7,991	**5,012**	8,988

(1) Conventional natural gas production yielded a heat content of 1.16 GJ/Mcf for the fourth quarter of 2020 and 1.17 GJ/Mcf for the year ended December 31, 2020, resulting in higher realized natural gas prices on a $/Mcf basis. See "Commodity Prices".
(2) Primarily heavy crude oil.
(3) Primarily related to West Central liquids-rich conventional natural gas.

Fourth quarter production averaged 4,730 boe/d, down 3,261 boe/d or 41% from 7,991 boe/d in the prior year period, due primarily to the sale of a 50% working interest in the East Edson property in West Central Alberta. The closing of the East Edson Transaction reduced West Central production during the fourth quarter of 2020 by 3,220 boe/d when compared to the prior year period. Production was lower than the 5,100 to 5,300 boe/d guidance released on November 10, 2020 with the Company's third quarter results, as the three (1.5 net) carried interest East Edson wells were tied-in to production later than forecast and operational shut-ins related to frac operations were greater than anticipated. In the fourth quarter of 2020, the production mix increased to 31% heavy crude oil and NGL (Q4 2019 – 24% heavy crude oil and NGL), primarily as a result of the East Edson Transaction.

Fourth quarter conventional natural gas production averaged 19.5 MMcf/d, down 47% from 36.6 MMcf/d in the comparative period of 2019. Conventional natural gas production was impacted by the sale of the 50% working interest in the East Edson property. Compared to the third quarter of 2020, conventional natural gas production increased by 20% or 3.2 MMcf/d, due to the full quarter of production from two (1.0 net) carried interest East Edson wells that were tied-in late in the third quarter, and three (1.5 net) carried interest wells tied-in later in the fourth quarter. Fourth quarter production was impacted by approximately 115 boe/d associated with adjacent wells that were shut-in during completion operations on the three new wells. Two (1.0 net) additional East Edson carried interest wells are forecast to be on production by the end of March 2021.

Fourth quarter NGL production was 237 bbl/d, 61% lower than the comparative period of 2019, tracking lower conventional natural gas production from West Central and lower NGL yields from the five (2.5 net) new carried interest wells that have been tied-in to production during the second half of 2020. NGL yields at West Central were 14.1 bbls per MMcf in the fourth quarter of 2020, 21% lower than the comparative period of 2019 (Q4 2019 – 17.9 bbls per MMcf). Perpetual's average NGL sales composition for the fourth quarter of 2020 consisted of 61% condensate, comparable to the prior year period.

Heavy crude oil production in Eastern Alberta was 2% lower than the fourth quarter of 2019. Ukalta production averaged 472 bbl/d in the fourth quarter of 2020 (Q4 2019 – 150 bbl/d), reflecting production added from the four (4.0 net) new wells drilled in the first quarter of 2020. Drilling at Ukalta more than offset natural heavy crude oil declines, but approximately 185 bbl/d of higher cost heavy crude oil production at Mannville remained shut-in in response to the significant decline in global oil prices. The Company continues to ramp up production as oil prices recover.

For the year ended December 31, 2020, production decreased 44% to 5,012 boe/d compared to 8,988 boe/d in the prior year period. Production levels decreased through 2019 and the first half of 2020 with restricted capital spending in response to low and volatile Alberta natural gas prices, price-driven heavy crude oil shut-ins in the second quarter of 2020, and the April 1, 2020 50% working interest disposition of the East Edson property.

Commodity Prices

	Three months ended December 31,		Years ended December 31,	
	2020	2019	**2020**	2019
Reference prices				
NYMEX Daily Index (US*$/MMBtu*)	**2.66**	2.50	**2.08**	2.63
AECO Daily Index (*$/GJ*)	**2.50**	2.35	**2.11**	1.67
AECO Daily Index *($/Mcf)*(1)	**2.64**	2.48	**2.23**	1.76
Alberta Gas Reference Price (*$/GJ*)(2)	**2.32**	2.01	**1.90**	1.40
West Texas Intermediate ("WTI") light oil (*US$/bbl*)	**42.66**	56.96	**39.40**	57.03
Western Canadian Select ("WCS") differential (*US$/bbl*)	**(9.30)**	(15.83)	**(12.60)**	(12.76)
WCS average (*Cdn$/bbl*)(3)	**43.37**	54.29	**35.91**	58.88
Average Perpetual prices				
Natural gas (*$/Mcf*)(1)				
AECO Daily Index	**2.64**	2.48	**2.23**	1.76
Heat Content Premium(4)	**0.27**	0.27	**0.24**	0.19
Market Diversification Contract	**(0.37)**	(0.05)	**(0.09)**	0.64
Realized gains (losses) on financial and physical gas derivatives(6)	**(1.18)**	(0.56)	**(1.53)**	0.16
Realized gains (losses) on prompt month price optimization	**0.10**	(0.14)	**–**	0.02
Realized natural gas price (*$/Mcf*)(5)	**1.46**	2.00	**0.85**	2.77
Percent of AECO Daily Index	**55%**	81%	**38%**	157%
Realized oil price (*$/bbl*)(5)	**52.60**	43.85	**49.37**	44.87
Realized natural gas liquids ("NGL") price (*$/bbl*)(5)	**38.03**	43.93	**31.40**	41.01

(1) Converted from $/GJ using a standard energy conversion rate of 1.06 GJ:1 Mcf.

(2) The Alberta Gas Reference Price is a representative market price for natural gas bought and sold within the province and is used to calculate Alberta Crown royalties.

(3) Derived internally using the Bank of Canada average foreign exchange rate of US$1.00 = Cdn$1.30 for the three months ended December 31, 2020 (Q4 2019 – $1.32) and $1.34 for the year ended December 31, 2020 (2019 – $1.33).

(4) Realized natural gas prices are at a premium to the AECO Daily Index due to higher average heat content of 1.16 GJ/Mcf for the fourth quarter of 2020 and 1.17 GJ/Mcf for the year ended December 31, 2020. Perpetual received a 10% premium to the AECO Daily Index for the fourth quarter of 2020 (Q4 2019 – 11%) and an 11% premium for the year ended December 31, 2020 (2019 – 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) For the fourth quarter of 2020, realized gains on derivatives include $0.5 million ($0.28/Mcf) of gains from the modification of the natural gas market diversification contract for the November 1, 2021 to October 31, 2022 period. For the year ended December 31, 2020, realized gains on derivatives include a net loss of $0.5 million ($0.06/Mcf) from the modification of the market diversification contract for the November 1, 2020 to October 31, 2022 period. For the year ended December 31, 2019, realized gains on derivatives include $2.7 million ($0.17/Mcf) from the elimination of the Company's 40,000 MMBtu/d market diversification contract obligations for the period of December 1, 2019 to October 31, 2020.

The fourth quarter of 2020 began with United States ("US") natural gas inventories approximately 310 Bcf above the 5-year average level. With global inventories of natural gas above historical averages, global LNG prices dropped to levels that resulted in low utilization of US LNG export capacity. The threat of early winter cold in North America, combined with flat production levels and higher LNG utilization, led to a price rally early in the fourth quarter of 2020. As the fourth quarter continued and cold weather failed to materialize, the elevated storage inventories weighed on the market, causing NYMEX natural gas prices to decline. For the fourth quarter of 2020, NYMEX natural gas prices increased 6% to US$2.66/MMBtu (Q4 2019 – US$2.50/MMBtu), while AECO Daily Index prices also increased 6% over the same period to $2.50/GJ (Q4 2019 – $2.35/GJ). The increase in AECO pricing was due to lower in-basin production compared to the prior year period, combined with increased exports to the Eastern and Western US markets. This led to strong storage withdrawals in Alberta and AECO-NYMEX basis to average US$0.56/MMBtu for the fourth quarter of 2020 (Q4 2019 – US$0.73/MMBtu). The North American drilling rig count remains wells below prior year levels.

WTI averaged US$42.66/bbl in the fourth quarter of 2020 (Q4 2019 – US$56.96/bbl). The decrease from the comparative period was related to significantly lower global demand driven by the economic contraction caused by the COVID-19 pandemic. Compared to the third quarter of 2020, WTI prices saw increased volatility due to overall financial market volatility, uncertainties associated with the US Presidential election campaign, a resurgence of COVID-19 induced shutdowns, and dissent between OPEC+ member countries which led to increased uncertainty. A turning point was reached in November 2020 following the US election, coinciding with positive vaccine developments and lower tensions among OPEC+ member countries. These factors led WTI crude, and equity markets to rally significantly through the second half of the fourth quarter. Focus remains on the global supply-demand balance, with OPEC continuing to help provide balance and bring global inventories back to normal levels. Concurrently, the US drilling rig count recovered from its summer 2020 lows but remains well below prior year levels.

The WCS differential tightened from an average US$15.83/bbl in the fourth quarter of 2019 to US$9.30/bbl in the fourth quarter of 2020. Production curtailments, facility turnarounds and natural production declines impacted the supply-demand balance in Alberta resulting in historically strong WCS differentials. These factors, combined with strong Gulf Coast Heavy Sour Mix pricing, led to a higher demand for Canadian heavy barrels. During the quarter, the government of Alberta lifted its curtailment program leading to increased domestic production for December 2020. As local inventories remain below 2019 levels, the market has increased confidence that it can remain balanced as incremental pipeline takeaway capacity is scheduled to come online later in 2021.

Perpetual's realized natural gas price, including derivatives, decreased 27% to $1.46/Mcf in the fourth quarter of 2020 from $2.00/Mcf in the comparative period of 2019. Compared to the AECO Daily Index, lower realized natural gas prices were the result of AECO-NYMEX basis hedging losses of $2.6 million ($1.46/Mcf) on financial and physical contracts, which occurred as Western Canadian gas storage filled rapidly. During the second quarter of 2020, the Company locked-in these remaining AECO-NYMEX basis hedge positions by entering into substantially offsetting hedge arrangements for the remainder of 2020 and 2021. The Company expects to realize a further loss of $3.4 million in 2021 on these locked-in positions. In the fourth quarter of 2020, the Company recorded a realized gain of $0.5 million ($0.28/Mcf) from the modification of the market diversification contract for the November 1, 2021 to October 31, 2022 period. In addition, the market diversification contract reduced the Company's realized natural gas price by $0.7 million ($0.37/Mcf) during the fourth quarter due to the relative increase in AECO Daily Index prices compared to the ex-AECO market hubs. In February 2021, the Company's remaining 10,000 MMBtu/d market diversification contract obligations were eliminated for the period of April 1, 2021 to October 31, 2021 in consideration for the payment of $1.4 million over the term of the associated contract volumes.

For the year ended December 31, 2020, Perpetual's realized natural gas price was $0.85/Mcf, down 69% from $2.77/Mcf in 2019 for the same reasons noted above. The market diversification contract reduced the Company's realized natural gas price by $0.7 million ($0.09/Mcf) due to the relative increase in AECO Daily Index prices compared to the two remaining downstream markets. For the year ended December 31, 2020, realized gains on derivatives include a net loss of $0.5 million ($0.06/Mcf) from the modification of the market diversification contract for the November 1, 2020 to October 31, 2022 period.

In the third quarter of 2020, the Company reduced its fixed volume obligations under the market diversification contract by 30,000 MMBtu/d to 10,000 MMBtu/d for the period commencing November 1, 2020 and ending on October 31, 2021 to align conventional natural gas sales obligations with lower forecast production volumes following the East Edson Transaction. The modification resulted in a realized loss on derivatives of $1.0 million. In the fourth quarter of 2020, the Company reduced its fixed volume obligations under the market diversification contract by 14,600 MMBtu/d to 25,400 MMBtu/d for the period November 1, 2021 to October 31, 2022, resulting in a realized gain of $0.5 million. The net impact of these modifications was a realized loss of $0.5 million or $0.06/Mcf for the year ended December 31, 2020. In the third quarter of 2019, the Company's 40,000 MMBtu/d market diversification contract obligations were eliminated for the period of December 1, 2019 to October 31, 2020 in response to TC Energy's changes to maintenance operating protocols, in order to shift the pricing point back to AECO, resulting in a realized gain of $2.7 million ($0.17/Mcf). Market diversification contract pricing is based on daily index prices at pricing hubs outside of Alberta that generally track North American NYMEX prices. See "Natural Gas Sales Obligations" on page 18 of this MD&A for sales volume obligations by price hub. Approximately 25% of 2021 forecast conventional natural gas production and 80% of 2022 forecast conventional natural gas production is expected to be delivered to the market diversification contract, with remaining production exposed to AECO prices.

During the fourth quarter of 2020, the average heat content conversion ratio for Perpetual's conventional natural gas production was 1.16 GJ:1 Mcf, consistent with the comparative period of 2019. Conventional natural gas production from East Edson yields higher heat content gas compared to Perpetual's other production areas.

Perpetual's realized oil price for the fourth quarter of 2020 was $52.60/bbl, 20% higher than the fourth quarter of 2019 due to realized gains on crude oil derivative contracts of $2.2 million ($18.92/bbl) that were entered into in late 2019, prior to the collapse of oil prices. Conversely, Perpetual's realized oil price in the fourth quarter of 2019 was reduced by $6.18/bbl associated with realized hedging losses.

For the year ended December 31, 2020, Perpetual's realized oil price was $49.37/bbl, up 10% from $44.87/bbl in 2019. Realized oil prices were improved by $19.05/bbl associated with realized hedging gains during the year (2019 – realized losses of $8.74/bbl).

Perpetual's realized NGL price for the fourth quarter of 2020 was $38.03/bbl, down 13% from the fourth quarter of 2019, reflecting a decrease in all NGL component prices which moved lower in concert with lower WTI light oil prices. For the year ended December 31, 2020, Perpetual's realized NGL price was $31.40/bbl, down 23% from the prior year period. The decrease was due to lower WTI light oil prices combined with realized hedging losses of $1.35/bbl on Perpetual's 350 bbl/d basis differential hedge between WTI and Edmonton condensate pricing that expired on June 30, 2020.

Revenue

	Three months ended December 31,		Years ended December 31,	
(*$ thousands, except as noted*)	**2020**	2019	**2020**	2019
Petroleum and natural gas revenue				
Natural gas(1)	**3,502**	7,263	**13,329**	39,318
Oil(1)	**3,846**	5,867	**12,015**	23,958
NGL	**830**	2,700	**4,142**	11,085
Petroleum and natural gas revenue	**8,178**	15,830	**29,486**	74,361
Realized gains (losses) on derivatives(2)	**1,278**	(1,495)	**708**	(789)
Realized revenue	**9,456**	14,335	**30,194**	73,572
Unrealized gains (losses) on derivatives	**(825)**	(3,369)	**9,901**	(21,893)
Total revenue	**8,631**	10,966	**40,095**	51,679
Realized revenue *($/boe)*	**21.73**	19.50	**16.46**	22.43
Total revenue *($/boe)*	**19.83**	14.92	**21.86**	15.75

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

Perpetual's petroleum and natural gas ("P&NG") revenue, before financial derivatives, for the three months ended December 31, 2020 of $8.2 million decreased 48% from the fourth quarter of 2019, due to the 41% decrease in average daily production combined with the impact of physical hedging losses on AECO-NYMEX basis natural gas contracts. For the year ended December 31, 2020, P&NG revenue decreased 60% compared to the prior year period, following the 44% decrease in average daily production combined with the decrease in crude oil and NGL reference prices along with physical AECO-NYMEX basis hedging losses.

Natural gas revenue, before derivatives, of $3.5 million in the fourth quarter of 2020 comprised 43% (Q4 2019 – 46%) of total P&NG revenue while conventional natural gas production was 69% (Q4 2019 – 76%) of total production. Natural gas revenue decreased 52% from $7.3 million in the fourth quarter of 2019, reflecting the combined impact of physical hedging losses, reduced revenue from the market diversification contract, and the 47% decrease in conventional natural gas production volumes driven by the East Edson Transaction.

Oil revenue of $3.8 million represented 47% (Q4 2019 – 37%) of total P&NG revenue while heavy crude oil production was 26% (Q4 2019 – 16%) of total production. Oil revenue was 34% lower than the same period in 2019, due primarily to the 20% decline in WCS average prices to $43.37/bbl (Q4 2019 – $54.29/bbl), as heavy crude oil production only declined by 3% over the same period. The lower WCS average reference price of $43.37/bbl was the result of a 25% decrease in WTI light oil prices to US$42.66/bbl (Q4 2019 – US$56.96/bbl) combined with a weaker US dollar of US$1.00 = Cdn$1.30 (Q4 2019 – $1.32), which more than offset a 41% narrowing of the WCS differential to US$9.30/bbl (Q4 2019 – US$15.83/bbl) compared to the prior year period. For the year ended December 31, 2020, oil revenue declined by 50% due to the 12% decrease in heavy crude oil production in combination with a 39% decrease in WCS average prices.

NGL revenue for the fourth quarter of 2020 of $0.8 million comprised 10% (Q4 2019 – 17%) of total P&NG revenue while NGL production represented only 5% (Q4 2019 – 8%) of total Company production. NGL revenue decreased by 69% over the comparative period of 2019 (Q4 2019 – $2.7 million) while NGL production decreased 61%, reflecting the decrease in all NGL component prices compared to the prior year period which generally track WTI light oil prices. For the year ended December 31, 2020, NGL revenue decreased by 63% due to the 52% decrease in NGL production combined with a 23% decrease in realized NGL prices over the prior year. The decrease in NGL production reflected lower conventional natural gas production at East Edson, combined with slightly lower NGL yields of 18.2 bbls per MMcf of conventional natural gas production (2019 – 18.6 bbls per MMcf).

Unrealized losses on derivatives of $0.8 million were recorded in the fourth quarter of 2020 (Q4 2019 – unrealized loss of $3.4 million). For the year ended December 31, 2020, Perpetual recorded net unrealized gains of $9.9 million, due primarily to the increased value of the Company's fixed price WTI and WCS oil contracts as global oil prices declined. 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 (used in) 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)	**2020**	2019	**2020**	2019
Crown	**451**	838	**1,382**	2,313
Freehold and overriding[(1)]	**1,380**	2,545	**5,189**	8,947
Total	**1,831**	3,383	**6,571**	11,260
Crown (*% of P&NG revenue*)	**5.5**	5.3	**4.7**	3.1
Freehold and overriding (*% of P&NG revenue*)	**16.9**	16.1	**17.6**	12.0
Total (*% of P&NG revenue*)	**22.4**	21.4	**22.3**	15.1
$/boe	**4.21**	4.60	**3.58**	3.43

(1) Includes $0.9 million in gross overriding royalty payments at East Edson for the three months ended December 31, 2020 (Q4 2019 – $1.9 million) and $3.9 million for the year ended December 31, 2020 (2019 – $5.7 million). Excludes the Purchaser's 50% working interest in the existing gross overriding royalty obligation, which is paid in-kind and settled through non-cash delivery of contractual natural gas and associated NGL volumes until December 31, 2022.

Royalty expense for the fourth quarter of 2020 was $1.8 million, representing 22.4% of P&NG revenue (Q4 2019 – 21.4%) and down 46% from $3.4 million in the prior year period. Higher royalty rates reflect the 15% increase in the Alberta Gas Reference Price and the 6% increase in the AECO Daily Index price compared to the prior year period which are used to calculate crown royalty and freehold and overriding royalty expense, respectively.

Freehold and overriding royalties have decreased 46% from the fourth quarter of 2019, due to the impact of the East Edson Transaction, partially offset by higher AECO Daily Index prices. The East Edson gross overriding royalty is equivalent to a maximum of 5.6 MMcf/d of conventional natural gas and associated NGL production. As part of the East Edson Transaction, Perpetual agreed to retain the Purchaser's 50% working interest in the existing gross overriding royalty obligation on the property, equivalent to 2.8 MMcf/d of conventional natural gas and associated NGL production for the period of April 1, 2020 to December 31, 2022. This additional obligation has been recorded in the consolidated statements of financial position under the heading "Royalty obligations". The retained East Edson royalty obligation is paid in-kind and settled through non-cash delivery of contractual natural gas and associated NGL volumes to the royalty holder.

For the year ended December 31, 2020, royalty expense was $6.6 million, representing 22.3% of P&NG revenue (2019 – 15.1%) and down 42% from $11.3 million in the prior year period. Average crown royalty rates increased to 4.7% in 2020 compared to 3.1% in 2019, due primarily to the 36% increase in Alberta Gas Reference Prices compared to the prior year, as well as the higher percentage of heavy crude oil in the production mix. Freehold and overriding royalties also increased as a percentage of P&NG revenue from 12.0% to 17.6%, as the AECO Daily Index increased 26% to $2.11/GJ (2019 – $1.67/GJ). In addition, as East Edson production decreased for much of 2020, 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 2020.

Production and operating expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2020**	2019	**2020**	2019
Production and operating expenses	**3,014**	3,839	**11,634**	18,332
$/boe	**6.93**	5.22	**6.34**	5.59

On an absolute dollar basis, production and operating costs were down by $0.8 million (21%) over the prior year period. This decrease reflects the impact of the East Edson Transaction, the elimination of variable costs related to the ongoing shut-in of 185 bbl/d of higher cost heavy crude oil production at Mannville, and other cost mitigation initiatives. Production and operating expenses were up 33% on a unit-of-production basis to $6.93/boe for the fourth quarter of 2020, compared to $5.22/boe for the comparable period of 2019 which reflects the increase in the Eastern Alberta production mix following the East Edson Transaction, which has higher operating costs compared to West Central.

For the year ended December 31, 2020, West Central production and operating costs increased by 25% on a unit-of-production basis to $3.42/boe (2019 – $2.74/boe). This increase includes $0.3 million of costs associated with the five-day West Wolf Lake plant turnaround, combined with natural production declines prior to the commencement of the carried interest drilling program at East Edson. Eastern Alberta operating costs decreased 21% to $13.27/boe over the same period (2019 – $16.85/boe) as a result of cost optimization activities and the continued temporary shut-in of certain higher cost heavy crude oil wells at Mannville.

Transportation costs

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2020**	2019	**2020**	2019
Transportation costs	**804**	1,551	**3,617**	6,258
$/boe	**1.85**	2.11	**1.97**	1.91

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 2020, transportation costs were $0.8 million, down 48% from the prior year period of $1.6 million. On a unit-of-production basis, company-wide transportation costs decreased by 12% to $1.85/boe in the fourth quarter of 2020 (Q4 2019 – $2.11/boe), due to a reduction in Perpetual's natural gas firm transportation capacity from 25.5 MMcf/d to 15.4 MMcf/d, eliminating unutilized demand charges at East Edson. Fourth quarter transportation costs averaged $1.21/boe at West Central compared to $2.98/boe for production from Eastern Alberta.

For the year ended December 31, 2020, transportation costs were $3.6 million, a decrease of 42% over the prior year period. The decrease was driven by a 44% decrease in total production, as per unit transportation costs of $1.97/boe were only 3% higher than the prior year period (2019 – $1.91/boe).

Exploration and evaluation ("E&E") expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2020**	2019	**2020**	2019
Lease rentals	**19**	52	**164**	190
Geological and geophysical costs	–	–	**19**	8
Lease expiries (non-cash)	**464**	759	**529**	1,599
Total E&E expense	**483**	811	**712**	1,797

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 year ended December 31, 2020, the Company recorded $0.5 million of non-cash write-downs (2019 – $1.6 million) associated with certain P&NG leases deemed to no longer be part of Perpetual's future development plans.

General and administrative ("G&A") expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2020**	2019	**2020**	2019
Cash G&A expense	**2,011**	2,604	**8,300**	12,808
Overhead recoveries	**(17)**	(198)	**(430)**	(1,148)
Total G&A expense	**1,994**	2,406	**7,870**	11,660
$/boe	**4.58**	3.27	**4.29**	3.55

During the fourth quarter of 2020, cash G&A expense was $2.0 million, a 23% decrease from the prior year period of $2.6 million due primarily to the reduction in work hours and corresponding employee compensation to 80%, effective April 1, 2020. During the fourth quarter of 2020, the Company received payments through the Canada Emergency Wage Subsidy of $0.3 million. These grants were recognized as a reduction to general and administrative and production and operating expenses of $0.2 million and $0.1 million, respectively (Q4 2019 – nil). Overhead recoveries decreased by 91% over the same period, due to reduced cash G&A expense associated with the transfer of operatorship at East Edson and decreased capital expenditures associated with the Company's decision to defer capital spending until oil prices recover and stabilize. On a unit-of-production basis, total G&A expense was up 40% to $4.58/boe for the fourth quarter of 2020 (Q4 2019 – $3.27/boe), as lower costs were more than offset by the 41% decline in production compared to the prior year period.

For the year ended December 31, 2020, total G&A expense was $7.9 million, down 33% from the prior year (2019 – $11.7 million). The decrease was driven by the 25% reduction in Perpetual's corporate employee head count that was implemented late in the third quarter of 2019, combined with the reduction in work hours and corresponding employee compensation to 80%, effective April 1, 2020. For the year ended December 31, 2020, the Company received payments through the Canada Emergency Wage Subsidy of $1.3 million. These grants were recognized as a reduction to G&A and production and operating expenses of $1.0 million and $0.3 million, respectively (2019 – nil). These reductions were partially offset by Sequoia Litigation legal costs and lower overhead recoveries triggered by the reduction in exploration and development spending from $12.9 million in 2019 to $6.0 million in 2020. On a unit-of-production basis, total G&A expense increased by 21% to $4.29/boe for the year ended December 31, 2020 (2019 – $3.55/boe), as lower costs were more than offset by the 44% decline in production compared to the prior year.

Share-based payments

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2020**	2019	**2020**	2019
Share-based payments (non-cash)	**104**	123	**517**	406
Share-based payments (cash)	**413**	365	**1,500**	1,889
Total share-based payments	**517**	488	**2,017**	2,295

Share-based payments expense for the fourth quarter of 2020 was $0.5 million, unchanged from the comparative period of 2019. During the fourth quarter of 2020, 0.2 million deferred shares were granted to Directors of the Company, with no further grants to employees. For the year ended December 31, 2020, share-based payments expense was $2.0 million, 12% lower than the prior year due to a reduction in the value of outstanding awards.

Depletion and depreciation

	Three months ended December 31,		Years ended December 31,	
($ thousands, except as noted)	**2020**	2019	**2020**	2019
Depletion and depreciation	**2,906**	6,960	**15,533**	31,188
$/boe	**6.68**	9.47	**8.47**	9.51

Perpetual recorded $2.9 million of depletion and depreciation expense for the fourth quarter of 2020, down 58% from the prior year period (Q4 2019 – $7.0 million). The decrease reflects the 41% decline in production volumes compared to the prior year period, combined with lower depletion rates on a unit-of-production.

Perpetual recorded $15.5 million of depletion and depreciation expense for the year ended December 31, 2020, down 50% from $31.2 million in 2019, due primarily to the 44% decline in production volumes compared to the prior year period. On a unit-of-production basis, depletion and depreciation expense decreased by 11% to $8.47/boe (2019 – $9.51/boe) due to non-cash impairments recognized in the fourth quarter of 2019 and the first quarter of 2020 (Q4 2019 – $24.5 million; Q1 2020 – $50.3 million).

Impairment

In accordance with IFRS, the Company is required to assess when internal or external indicators of impairment or impairment reversal exist, and impairment testing is required. At December 31, 2020, the Company conducted an assessment of indicators of impairment and impairment reversal for all the Company's cash-generating units ("CGUs"). In performing the assessment, management determined that the recovery in global oil and gas commodity prices, changing development plans, positive reserve revisions, and increasing economic stability and certainty in the oil and gas industry, all of which positively impacts operating cash flows, justified calculation of the estimated recoverable amount of the liquids-rich conventional natural gas assets and heavy crude oil assets which comprise the West Central CGU and Eastern Alberta CGU, respectively. The estimated recoverable amounts of the CGUs were determined on a value-in-use basis using estimates of proved and probable oil and gas reserves and the related cash flows as evaluated by the Company's independent third party reserves evaluators at December 31, 2020, along with oil and gas commodity price estimates based on an average of three independent third party reserve evaluators, and an estimate of market discount rates between 12% and 25% to consider risks specific to the CGUs.

At December 31, 2020, the Company determined that the estimated recoverable amounts of the West Central CGU and Eastern Alberta CGU exceeded the carrying amounts of $81.2 million and $24.7 million, respectively. Accordingly, an aggregate non-cash impairment reversal of $18.0 million was included in net income (loss).

At March 31, 2020, the Company conducted an assessment of internal and external indicators of impairment for all the Company's CGUs. In performing the assessment, management determined that the significant decline in global oil and gas commodity prices that was experienced following the onset of the COVID-19 pandemic, coupled with the considerable economic instability and uncertainty in the oil and gas industry which negatively impacts operating cash flows, justified calculation of the estimated recoverable amount of the liquids-rich conventional natural gas assets and heavy crude oil assets which comprise the West Central CGU and Eastern Alberta CGU, respectively. At March 31, 2020, the Company determined that the carrying amounts of the West Central CGU and Eastern Alberta CGU exceeded the estimated recoverable amounts and accordingly, an aggregate non-cash impairment charge of $50.3 million was included in net loss. For the year ended December 31, 2020, the Company has recorded an aggregate non-cash impairment charge of $32.3 million related to these CGUs in net loss.

E&E assets are tested 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. At December 31, 2020, the Company conducted an assessment of indicators of impairment and impairment reversal for the Company's E&E assets. In performing the assessment, management determined that the recovery in global oil and gas commodity prices from depressed levels experienced earlier in 2020, coupled with the increasing economic stability and certainty in the oil and gas industry which positively impacts operating cash flows, justified calculation of the estimated recoverable amount of E&E assets. The estimated recoverable amount was determined based on the sales value of undeveloped lands. As a result of this calculation, no impairment or impairment reversal was recognized during the fourth quarter of 2020.

At March 31, 2020, management determined that the significant decline in global oil and gas prices, coupled with the considerable economic instability and uncertainty in the oil and gas industry, justified calculation of the estimated recoverable amount of E&E assets. As a result of this calculation, the carrying value of E&E assets was written down to the estimated recoverable amount, resulting in a non-cash impairment charge of $10.2 million.

Finance expenses

	Three months ended December 31,		Years ended December 31,	
($ thousands)	**2020**	2019	**2020**	2019
Cash finance expense				
Interest on revolving bank debt	**293**	788	**1,662**	2,880
Interest on TOU share margin demand loan	**–**	72	**–**	407
Interest on term loan	**(912)**	936	**1,812**	3,645
Interest on senior notes	**733**	735	**2,938**	2,921
Interest on lease liabilities	**41**	44	**175**	189
Dividend income from TOU share investment	**–**	(199)	**–**	(762)
Total cash finance expense	**155**	2,376	**6,587**	9,280
Non-cash finance expense				
Interest paid in-kind	**1,823**	–	**1,823**	–
Amortization of debt issue costs	**502**	326	**1,673**	1,187
Accretion on decommissioning obligations	**96**	162	**443**	752
Change in fair value of royalty obligations	**(914)**	117	**1,305**	732
Total non-cash finance expense	**1,507**	605	**5,244**	2,671
Finance expenses recognized in net loss	**1,662**	2,981	**11,831**	11,951

Total cash finance expense was $0.2 million in the fourth quarter of 2020, 93% lower than the prior year period (Q4 2019 – $2.4 million). The decrease was due primarily to $1.8 million of Term Loan interest for the July 1, 2020 to December 31, 2020 period that the lender agreed could be paid in-kind and added to the principal amount owing as a condition of the Credit Facility lenders agreeing to extend the Credit Facility maturity to March 1, 2021. Interest on revolving bank debt also decreased by $0.5 million due to lower average borrowings and lower floating interest rates.

In January 2020, the Company sold its remaining 1,000,000 TOU share investment and used the net cash proceeds of $14.3 million to repay the remaining $0.1 million TOU share margin demand loan, with the balance used to repay a portion of the Credit Facility. Accordingly, the Company no longer receives dividend income from its TOU share investment or incurs interest expense on the TOU share margin demand loan.

Total non-cash finance expense for the fourth quarter of 2020 was $1.5 million, $0.9 million higher than the prior year period (Q4 2019 – $0.6 million) and due primarily to $1.8 million of Term Loan interest for the July 1, 2020 to December 31, 2020 period that the lender agreed could be paid in-kind. For the year ended December 31, 2020, total non-cash finance expense was $5.2 million, an increase of 96% from the prior year (2019 – $2.7 million). The increase included $1.8 million of interest paid in-kind on the Term Loan (2019 – nil) and the change in fair value of royalty obligations of $1.3 million (2019 – $0.7 million) which resulted from higher AECO future natural gas prices.

In January 2021, the Company exchanged it's $33.6 million 8.75% unsecured senior notes due January 23, 2022 for new $33.6 million 8.75% third lien senior notes due January 23, 2025. Interest on the 2025 Senior Notes may be paid in-kind at the option of the Company by adding the interest payment to the principal amount owing. On January 23, 2021, the $1.5 million semi-annual interest on the 2025 Senior Notes was paid in-kind, increasing the principal amount owing to $35.0 million. Perpetual intends to pay in-kind the 2025 Senior Notes semi-annual interest payment due on July 23, 2021.

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, 2020**	December 31, 2019
Revolving bank debt	**17,495**	47,552
Term loan, principal amount	**46,823**	45,000
TOU share margin demand loan, principal amount	**–**	100
Senior notes, principal amount	**33,580**	33,580
TOU share investment[1]	**–**	(15,220)
Net working capital deficiency[2]	**7,099**	7,068
Net debt[2]	**104,997**	118,080
Shares outstanding at end of period (*thousands*)[3]	**61,305**	60,513
Market price at end of period (*$/share*)[3]	**0.08**	0.07
Market value of shares	**4,904**	4,236
Enterprise value[2]	**109,901**	122,316
Net debt as a percentage of enterprise value	**96**	97
Trailing twelve months adjusted funds flow[2]	**(7,787)**	14,534
Net debt to trailing twelve months adjusted funds flow	**N/A**	8.1

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

At December 31, 2020, Perpetual had total net debt of $105.0 million, down $13.1 million (11%) from December 31, 2019 due to the closing of the East Edson Transaction on April 1, 2020 for consideration including net cash proceeds of $34.8 million. The cash proceeds from the East Edson Transaction were used to repay bank debt. Compared to September 30, 2020, net debt increased by $2.9 million (3%) due to increased draws on the Credit Facility to fund net working capital payments and cash flows used in operating activities.

Perpetual had available liquidity at December 31, 2020 of $1.6 million, comprised of the $20 million Credit Facility Borrowing Limit, less current borrowings and letters of credit of $17.5 million and $0.9 million, respectively.

Revolving bank debt

As at December 31, 2020, the Company's Credit Facility had a Borrowing Limit of $20.0 million (December 31, 2019 – $55.0 million) under which $17.5 million was drawn (December 31, 2019 – $47.6 million) and $0.9 million of letters of credit had been issued (December 31, 2019 – $2.3 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%. The effective interest rate on the Credit Facility at December 31, 2020 was 6.95%. For the period ended December 31, 2020, if interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net loss would be $0.2 million.

Effective April 1, 2020, Perpetual's syndicate of Credit Facility lenders completed their borrowing base redetermination, incorporating the impact of the East Edson Transaction. The Borrowing Limit was reduced from $45 million to $20 million. The next Borrowing Limit redetermination, and current maturity date, is scheduled to be completed by March 1, 2021. If not extended by March 1, 2021, the Credit Facility will cease to revolve, and all outstanding advances will be repayable. As a result, revolving bank debt has been presented as a current liability on the consolidated statements of financial position as at December 31, 2020. Previously, 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.

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 Term Loan and senior note principal and interest, and to pay dividends on or repurchase its common shares.

At December 31, 2020, the Credit Facility was not subject to any additional financial covenants and the Company was in compliance with all customary non-financial covenants.

Term loan

	Maturity date	Interest rate	**December 31, 2020** Principal	Carrying Amount	December 31, 2019 Principal	Carrying amount
Term Loan	March 14, 2021	8.1%	**$ 46,823**	**$ 46,691**	$ 45,000	$ 44,274

The Term Loan bears a fixed interest rate of 8.1% with semi-annual interest payments due June 30th and December 31st of each year. In the fourth quarter of 2020, the Company and lender reached an agreement, allowing outstanding interest amounts of $1.8 million related to the December 31st payment to be paid-in-kind and added to the outstanding principal amount of the loan.

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 matures and is repayable on March 14, 2021 and has been presented as a current liability on the consolidated statements of financial position as at December 31, 2020.

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

At December 31, 2020, the Term Loan is presented net of $0.1 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 9.2%.

At December 31, 2020, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Senior notes

	Maturity date	Interest rate	**December 31, 2020** Principal	Carrying Amount	December 31, 2019 Principal	Carrying amount
2022 Senior Notes	January 23, 2022	8.75%	**$ 33,580**	**$ 32,359**	$ 33,580	$ 32,255

The 2022 Senior Notes bear a fixed interest rate of 8.75% with semi-annual interest payments due January 23rd and July 23rd 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. The Company may redeem the senior notes without any repayment penalty.

At December 31, 2020, the 2022 Senior Notes are recorded at the present value of future cash flows, net of 1.2 million in issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 12.4%.

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, 2020, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Entities controlled by the Company's CEO hold $14.6 million of the 2022 Senior Notes outstanding. An entity that is associated with the Company's CEO holds an additional $9.1 million of the 2022 Senior Notes outstanding.

On January 22, 2021, the Company announced the completion of a Court-approved plan of arrangement whereby the 2022 Senior Notes were exchanged for new 8.75% secured third lien notes due January 23, 2025 (the "2025 Senior Notes"). The 2025 Senior Notes have been issued under a trust indenture that contains substantially the same terms as the 2022 Senior Notes, other than the 2025 Senior Notes are secured on a third lien basis and allow for the semi-annual interest payments to be paid at Perpetual's option, in either cash, or in additional 2025 Senior Notes (a "PIK Interest Payment"). The Company elected to pay the January 23, 2021 interest payment of $1.5 million by a PIK Interest Payment which increased the principal amount of the 2025 Senior Notes outstanding to $35.0 million.

Equity

At December 31, 2020 there were 61.3 million common shares outstanding, net of 0.6 million shares held in trust to resource employee compensation programs. Basic and diluted weighted average shares outstanding for the three months ended December 31, 2020 were 61.3 million (Q4 2019 – 60.4 million) and 61.0 million for the year ended December 31, 2020 (2019 – 60.3 million).

At February 24, 2021, there were 61.4 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)	**February 24, 2021**
Share options	**5.4**
Performance share rights	**3.4**
Compensation awards	**7.5**
Total(1)	**16.3**

(1) 4.6 million compensation awards, 0.9 million share options, and 3.4 million performance share rights have an exercise price below the December 31, 2020 closing price of the Company's common shares of $0.08 per share.

SUMMARY OF QUARTERLY RESULTS

($ thousands, except as noted)	**Q4 2020**	Q3 2020	Q2 2020	Q1 2020
Financial				
Oil and natural gas revenue	**8,178**	7,089	3,722	10,497
Net income (loss)	**14,443**	(7,491)	(8,831)	(59,718)
Per share – basic and diluted	**0.24**	(0.12)	(0.15)	(0.98)
Cash flow from (used in) operating activities	**(1,104)**	(2,538)	(2,777)	(3,114)
Adjusted funds flow(1)	**1,240**	(2,098)	(3,328)	(3,601)
Per share – basic and diluted	**0.02**	(0.03)	(0.05)	(0.06)
Capital expenditures	**466**	251	(11)	5,233
Net payments (proceeds) on acquisitions and dispositions	**–**	133	(34,661)	–
Net capital expenditures	**466**	384	(34,672)	5,233
Common shares *(thousands)*				
Weighted average – basic and diluted	**61,266**	61,200	60,776	60,674
Operating				
Daily average production				
Conventional natural gas *(MMcf/d)*	**19.5**	16.3	16.9	33.3
Heavy crude oil *(bbl/d)*	**1,241**	1,193	573	1,320
NGL *(bbl/d)*	**237**	273	268	606
Total *(boe/d)*	**4,730**	4,188	3,662	7,479
Average prices				
Realized natural gas price *($/Mcf)*(2)	**1.46**	0.06	0.28	1.16
Realized oil price *($/bbl)*(2)	**52.60**	55.71	67.56	32.60
Realized NGL price *($/bbl)*(2)	**38.03**	28.09	17.35	36.48

($ thousands, except where 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 operating activities	(1,290)	5,509	4,295	9,292
Adjusted funds flow(1)	340	4,183	3,649	6,362
Per share – basic	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				
Conventional natural gas (*MMcf/d*)	36.6	38.2	44.5	50.0
Heavy crude 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

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

(2) Realized natural gas, oil and NGL 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.

The Company's oil and natural gas revenue, net income (loss), cash flow from (used in) operating activities and adjusted funds flow are influenced by commodity prices and production levels. Conventional natural gas production levels decreased during 2019 and 2020 due to natural declines and reduced capital expenditures in response to depressed and volatile AECO natural gas prices. The disposition of a 50% working interest in the East Edson property which closed on April 1, 2020 for net cash consideration of $34.8 million and an eight well carried capital commitment, further reduced conventional natural gas production in the second and third quarters of 2020, before increasing slightly in the fourth quarter as five (2.5 net) new carried interest wells have been tied-in to production. Oil-focused capital expenditures increased beginning in the second quarter of 2019, as improved oil prices and differentials supported investment. In response to the significant decline in global oil prices which began in March 2020, oil-focused capital expenditures and high-cost production was temporarily suspended, pending a recovery of oil prices, and oil focused hedging gains were locked-in. Heavy crude oil production was restarted mid-way through the second quarter, following the recovery of oil prices.

For the year ended December 31, 2020, the Company's net loss was impacted by net impairment charges of $42.5 million (Q4 2020 – $18.0 million impairment reversal; Q1 2020 – $60.5 million impairment charge), compared to total impairments of $47.1 million in the prior year (Q2 2019 – $22.6 million; Q4 2019 – $24.5 million). Perpetual also recognized $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 contracts 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 open commodity price risk management contracts outstanding at February 24, 2021:

Heavy crude oil

The following tables provide a summary of physical fixed price WTI, WCS and WTI-WCS basis differential contracts which settle in US$:

Term	Volumes sold (bought) *(bbl/d)*	WTI *(US$/bbl)*	Market prices *(US$/bbl)*[1]
January 2021	203	44.05	52.10
January 2021 – March 2021	203	41.50	58.05
April 2021 – June 2021	203	53.90	62.31

Term	Volumes sold (bought) *(bbl/d)*	WTI-WCS differential *(US$/bbl)*	Market prices *(US$/bbl)*[1]
April 2021 – June 2021	203	(11.90)	(11.27)
April 2021 – September 2021	203	(14.20)	(11.23)
January 2021 – December 2021	310	(13.25)	(11.82)

(1) Market prices for January and February 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 February 24, 2021.

Term	Volumes sold (bought) *(bbl/d)*	WCS *(US$/bbl)*	Market prices *(US$/bbl)*[1]
January 2021	203	33.70	40.04
February 2021	337	31.05	44.96
March 2021	406	32.75	51.74

Conventional natural gas sales obligations

In the third quarter of 2020, the Company reduced its fixed volume obligations by 30,000 MMBtu/d for the period commencing November 1, 2020 and ending on October 31, 2021 in consideration for the payment of $1.0 million over the term of the associated contract volumes. In the fourth quarter of 2020, the Company reduced its fixed volume obligation by 14,600 MMBtu/d for the period commencing November 1, 2021 and ending on October 31, 2022 in consideration for the receipt of $0.5 million over the term of the associated contract volumes. For the year ended December 31, 2020, these modifications have been recognized as a net realized loss on derivatives of $0.5 million in the consolidated statements of loss and comprehensive loss.

In February 2021, the Company's 10,000 MMBtu/d market diversification contract obligations were eliminated for the period of April 1, 2021 to October 31, 2021 in consideration for the payment of $1.4 million over the term of the associated contract volumes.

Conventional natural gas volumes sold pursuant to the Company's market diversification contract are sold at fixed volume obligations 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.

Market/Pricing Point	November 1, 2020 to March 31, 2021 Daily sales volume *(MMBtu/d)*	November 1, 2021 to October 31, 2022 Daily sales volume *(MMBtu/d)*	November 1, 2022 to October 31, 2024 Daily sales volume *(MMBtu/d)*
Chicago	4,000	12,200	–
Malin	–	–	15,000
Dawn	6,000	8,000	15,000
Michcon	–	5,200	–
Emerson	–	–	10,000
Total sales volume obligation	**10,000**	**25,400**	**40,000**

SELECTED ANNUAL INFORMATION

($ thousands, except where noted)	**2020**	2019	2018[4]
Financial			
Oil and natural gas revenue	**29,486**	74,361	86,128
Net income (loss)	**(61,597)**	(94,015)	(20,380)
Per share – basic and diluted[1]	**(1.01)**	(1.56)	(0.34)
Cash flow from (used in) operating activities	**(9,533)**	17,806	31,525
Adjusted funds flow	**(7,787)**	14,534	30,155
Per share[1][2]	**(0.13)**	0.24	0.50
Total assets	**140,454**	241,148	335,089
Total long-term liabilities	**68,722**	118,061	101,870
Revolving bank debt	**17,495**	47,552	42,561
Senior notes, principal amount	**33,580**	33,580	32,490
Term loan, principal amount	**46,823**	45,000	45,000
TOU share margin demand loan, principal amount	**–**	100	14,144
TOU share investment	**–**	(15,220)	(28,132)
Net working capital deficiency	**7,099**	7,068	6,543
Total net debt	**104,997**	118,080	112,606
Net capital expenditures			
Capital expenditures	**5,939**	12,939	26,888
Net proceeds on acquisitions and dispositions	**(34,528)**	–	(3,030)
Net capital expenditures	**(28,589)**	12,939	23,858
Common shares (*thousands*)			
End of period[3]	**61,305**	60,513	60,240
Weighted average – basic and diluted	**61,013**	60,258	60,039
Operating			
Daily average production			
Conventional natural gas (*MMcf/d*)	**21.5**	42.3	52.6
Heavy crude oil (*bbl/d*)	**1,082**	1,224	1,050
NGL (*bbl/d*)	**346**	719	774
Total average production (*boe/d*)	**5,012**	8,988	10,594
Average prices			
Realized natural gas price (*$/Mcf*)	**0.85**	2.77	3.05
Realized oil price (*$/bbl*)	**49.37**	44.87	40.62
NGL price (*$/bbl*)	**31.40**	41.01	52.96
Wells drilled			
Conventional natural gas – gross (net)	**5 (2.5)**	– (–)	1 (1.0)
Heavy crude oil – gross (net)	**4 (4.0)**	5 (5.0)	6 (6.0)
Total – gross (net)	**9 (6.5)**	5 (5.0)	7 (7.0)

(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 (2020 – 556; 2019 – 801; 2018 – 661). See "Note 16 to the Consolidated Financial Statements".
(4) IFRS 16 was adopted January 1, 2019 using the modified retrospective approach; therefore, comparative information has not been restated.

OFF BALANCE SHEET ARRANGEMENTS

Perpetual has no off balance sheet arrangements.

CHANGES IN ACCOUNTING POLICIES

Government grants

Government grants are recognized when there is reasonable assurance that the grant will be received, and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as an expense reduction in the period in which the costs are incurred. Government grants related to income are recorded as other income in the period in which eligible expenses were incurred or when the services have been performed.

For the year ended December 31, 2020, the Company received government grants through the Canada Emergency Wage Subsidy and Canada Emergency Rent Subsidy of $1.3 million. These grants were recognized as a reduction to G&A and production and operating expenses of $1.0 million and $0.3 million, respectively (2019 – nil). For the year ended December 31, 2020, the Company also received government grants through the Alberta Site Rehabilitation program of $0.8 million to fund approved abandonment and remediation projects. These grants were recognized as "Other income" in the consolidated statements of loss and comprehensive loss. Associated expenditures were recorded as a reduction to decommissioning obligations on the consolidated statements of financial position.

ACCOUNTING PRONOUNCEMENTS

Amendments to IFRS 3 "Business Combinations"

On January 1, 2020, the Company adopted the 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.

No business combinations were completed during the year ended December 31, 2020.

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 2020 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, 2020, 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, 2020 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, 2020, the internal controls over financial reporting were designed and operating effectively.

INTERNAL CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures

There were no changes in the Corporation's internal control over financial reporting during the period beginning on October 1, 2020 and ended December 31, 2020 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 2020 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 proved and probable oil and gas reserves and the related cash flows, sales value of undeveloped lands, derivative financial instruments, provisions for decommissioning and royalty obligations and share-based payments, income taxes, and the amount and likelihood of contingent liabilities. Critical accounting estimates are based on assumptions and data including:

- Estimation of recoverable proved and probable oil and gas reserves and the related future cash flows from reserves;
- Forecasted oil and gas commodity prices;
- Forecasted operating costs, royalty costs and future development costs;
- Sales value of undeveloped lands;
- 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, inflation rates, and volatility in stock prices and oil and gas commodity prices; and
- Estimation of future abandonment and reclamation costs and timelines.

A change in a critical accounting estimate can have a significant effect on net loss, including their impact on the depletion rate, provisions, impairments, 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, 2020.

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 headings "Future Operations" and "Outlook" may constitute forward-looking information and statements within the meaning of applicable securities laws. This information and these statements relate to future events or to future performance. All statements other than statements of historical fact may be forward-looking information and statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook", "guidance", "objective", "plans", "intends", "targeting", "could", "potential", "strategy" and any similar expressions are intended to identify forward-looking information and statements.

In particular, but without limiting the foregoing, this MD&A contains forward-looking information and statements pertaining to the following: the potential outcome of the Sequoia Litigation, the ability to extend the Credit Facility or to refinance its Term Loan on favorable terms; the quantity and recoverability of Perpetual's reserves; the timing and amount of future production; future prices as well as supply and demand for conventional natural gas, NGL and heavy crude oil; the existence, operations and strategy of the commodity price risk management program; the approximate amount of forward sales and financial contracts to be employed, and the value of financial forward natural gas, oil and other risk management contracts; net income (loss) and adjusted funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes; production and operating, general and administrative ("G&A"), and other expenses; the costs and timing of future abandonment and reclamation, asset retirement and environmental obligations; the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Corporation's asset base; the Corporation's acquisition and disposition strategy and the existence of acquisition and disposition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom; Perpetual's ability to benefit from the combination of growth opportunities and the ability to grow through the capital expenditure program; expected compliance with credit facility and Term Loan covenants in 2021 and 2022; 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.

Various assumptions were used in drawing the conclusions or making the forecasts and projections in the forward-looking information contained in this MD&A, which assumptions are based on management's analysis of historical trends, experience, current conditions and expected future developments pertaining to Perpetual and the industry in which it operates as well as certain assumptions regarding the matters outlined above. Forward-looking information is based on current expectations, estimates and projections that involve a number of known and unknown risks, including, without limitation, the impact of COVID-19 as further described below, which could cause actual results to vary and in some instances to differ materially from those anticipated by Perpetual and described in the forward-looking information contained in this MD&A. In particular and without limitation of the foregoing, the recent outbreak of COVID-19 has had a negative impact on global financial conditions. Perpetual cannot accurately predict the impact that COVID-19 will have on its ability to execute its business plans in response to government public health efforts to contain COVID-19 and to obtain financing or third parties' ability to meet their contractual obligations with Perpetual including due to uncertainties relating to the ultimate geographic spread of the virus, the severity of the disease, the duration of the outbreak, and the length of travel and quarantine restrictions imposed by governments of affected jurisdictions; and the current and future demand for oil and gas. In the event that the prevalence of COVID-19 continues to increase (or fears in respect of COVID-19 continue to increase), governments may increase regulations and restrictions regarding the flow of labour or products, and travel bans, and Perpetual's operations, service providers and customers, and ability to advance its business plan or carry out its top strategic priorities, could be adversely affected. In particular, should any employees, consultants or other service providers of Perpetual become infected with COVID-19 or similar pathogens, it could have a material negative impact on Perpetual's operations, prospects, business, financial condition and results of operations. Undue reliance should not be placed on forward-looking information, which is not a guarantee of performance and is subject to a number of risks or uncertainties, including without limitation those described herein and under "Risk Factors" in Perpetual's Annual Information Form and MD&A for the year ended December 31, 2020 and in other reports on file with Canadian securities regulatory authorities which may be accessed through the SEDAR website (www.sedar.com) and at Perpetual's website (www.perpetualenergyinc.com).

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.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. Forward-looking information is based on the estimates and opinions of Perpetual's management at the time the information is released, and Perpetual disclaims any intent or obligation to update publicly any such forward-looking information, whether as a result of new information, future events or otherwise, other than as expressly required by applicable securities law.

OIL AND GAS ADVISORIES

This MD&A contains metrics commonly used in the oil and natural gas industry, such as "finding and development" costs or "F&D" costs. 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.

CONSOLIDATED FINANCIAL STATEMENTS

MANAGEMENT'S REPORT

The consolidated financial statements of Perpetual Energy Inc. ("Perpetual" or 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 2020 to 2019 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 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	**W. Mark Schweitzer**
President & Chief Executive Officer	Vice President, Finance & Chief Financial Officer

February 24, 2021

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, 2020 and December 31, 2019
- 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, 2020 and December 31, 2019, 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 March 1, 2021 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.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2020. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

In addition to the matter described in the ***"Material Uncertainty related to Going Concern"*** section of the auditors' report, we have determined the matters described below to be the key audit matters to be communicated in our auditors' report.

Assessment of the recoverable amount of the cash generating units and exploration and evaluation assets

Description of the matter

We draw attention to note 2, note 3, note 5 and note 6 to the financial statements. Significant judgment is required to assess when internal or external indicators of impairment or impairment reversal exist, and impairment testing is required. The Company identified indicators of impairment at March 31, 2020 and indicators of reversal at December 31, 2020 for all cash generating units (the "CGUs") and exploration and evaluation assets and performed impairment tests to estimate the recoverable amount of each CGU and of the combined CGUs and exploration and evaluation assets. The Company has recorded an aggregate non-cash impairment charge of $32.3 million related to the CGUs and $10.2 million related to exploration and evaluation assets.

The estimated recoverable amount of each CGU and exploration and evaluation assets involves significant estimates including:

- The estimate of proved and probable oil and gas reserves and the related cash flows
- The discount rates
- The sales value of the undeveloped lands.

The estimate of proved and probable oil and gas reserves and the related cash flows requires the expertise of independent third party reserve evaluators and includes significant assumptions related to:

- Forecasted oil and gas commodity prices
- Forecasted production
- Forecasted operating costs
- Forecasted royalty costs

- Forecasted future development costs.

The Company engages independent third party reserve evaluators to estimate the proved and probable oil and gas reserves and the related cash flows.

Why the matter is a key audit matter

We identified the assessment of the recoverable amount of the CGUs and exploration and evaluation assets as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and gas reserves and the related cash flows, the discount rates, and the sales value of the undeveloped lands.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

With respect to the estimate of proved and probable oil and gas reserves and the related cash flows:

- We evaluated the competence, capabilities and objectivity of the independent third party reserve evaluators engaged by the Company
- We compared forecasted oil and gas commodity prices to those published by other independent third party reserve evaluators
- We compared the 2020 actual production, operating costs, royalty costs and development costs of the Company to those estimates used in the prior year's estimate of proved oil and gas reserves and the related cash flows to assess the Company's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to 2020 historical results. We took into account changes in conditions and events affecting the Company to assess the adjustments or lack of adjustments made by the Company in arriving at the assumptions.

We involved valuation professionals with specialized skills and knowledge, who assisted in:

- Evaluating the appropriateness of the Company's discount rates by comparing the discount rates to market and other external data
- Assessing the reasonableness of the Company's estimate of the recoverable amount of each CGU and the sales value of the undeveloped lands by comparing the Company's estimates to market metrics and other external data.

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 "2020 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 "2020 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.
- Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditors' report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditors' report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

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

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 24, 2021

PERPETUAL ENERGY INC.
Consolidated Statements of Financial Position

As at	**December 31, 2020**	December 31, 2019
(*Cdn$ thousands*)		
Assets		
Current assets		
Accounts receivable (note 20)	**$ 3,953**	$ 5,056
Tourmaline Oil Corp. ("TOU") share investment (note 4)	**–**	15,220
Prepaid expenses and deposits	**872**	1,154
	4,825	21,430
Property, plant and equipment (note 5)	**123,985**	194,634
Exploration and evaluation (note 6)	**10,272**	23,609
Right-of-use assets (note 7)	**1,372**	1,475
Total assets	**$ 140,454**	$ 241,148
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 11,924**	$ 13,278
TOU share margin demand loan	**–**	100
Revolving bank debt (note 9)	**17,495**	47,552
Term loan (note 10)	**46,691**	–
Fair value of derivatives (note 21)	**3,373**	10,542
Royalty obligations (note 12)	**3,553**	582
Lease liabilities (note 13)	**710**	633
Provisions (note 14)	**1,048**	2,382
	84,794	75,069
Fair value of derivatives (note 21)	**–**	2,732
Term loan (note 10)	**–**	44,274
Senior notes (note 11)	**32,359**	32,255
Royalty obligations (note 12)	**2,596**	289
Lease liabilities (note 13)	**1,791**	2,052
Provisions (note 14)	**31,976**	36,459
Total liabilities	**153,516**	193,130
Equity		
Share capital (note 16)	**97,333**	96,876
Warrants (note 16(c))	**–**	923
Contributed surplus	**45,217**	44,234
Deficit	**(155,612)**	(94,015)
Total equity	**(13,062)**	48,018
Total liabilities and equity	**$ 140,454**	$ 241,148

Future operations (note 1)
Contingencies (note 8)
Contractual obligations (note 15)

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, 2020		December 31, 2019
(*Cdn$ thousands, except per share amounts*)				
Revenue				
Oil and natural gas (note 18)	**$**	**29,486**	$	74,361
Royalties		**(6,571)**		(11,260)
		22,915		63,101
Change in fair value of derivatives (note 21)		**10,609**		(22,682)
Gas over bitumen royalty credit		**685**		852
Other income (note 14(a))		**812**		–
		35,021		41,271
Expenses				
Production and operating		**11,634**		18,332
Transportation		**3,617**		6,258
Exploration and evaluation (note 6)		**712**		1,797
General and administrative		**7,870**		11,660
Share-based payments (note 17)		**2,017**		2,295
Depletion and depreciation (note 5 and 7)		**15,533**		31,188
Impairment (note 5(b) and 6)		**42,500**		47,052
Net loss from operating activities		**(48,862)**		(77,311)
Finance expense (note 19)		**(11,831)**		(11,951)
Change in fair value of TOU share investment (note 4)		**(904)**		(3,207)
Restructuring costs (note 14(b))		**–**		(1,546)
Net loss and comprehensive loss		**(61,597)**		(94,015)
Loss per share (note 16d)				
Basic and diluted	**$**	**(1.01)**	$	(1.56)

See accompanying notes to the consolidated financial statements.

PERPETUAL ENERGY INC.
Consolidated Statements of Changes in Equity

	Share capital			Contributed		
	(thousands)	*($thousands)*	Warrants	surplus	Deficit	Total equity
(Cdn$ thousands, except share amounts)						
Balance at December 31, 2019	60,513	$ 96,876	$ 923	$ 44,234	$ (94,015)	$ 48,018
Net loss	–	–	–	–	(61,597)	(61,597)
Common shares issued (note 16 and 17)	548	340	(923)	583	–	–
Change in shares held in trust (note 16 and 17)	244	117	–	(117)	–	–
Share-based payments (note 17)	–	–	–	517	–	517
Balance at December 31, 2020	**61,305**	**$ 97,333**	**$ –**	**$ 45,217**	**$ (155,612)**	**$ (13,062)**

	Share capital			Contributed		
	(thousands)	*($thousands)*	Warrants	surplus	Deficit	Total equity
(Cdn$ thousands, except share amounts)						
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 16 and 17)	412	690	–	(690)	–	–
Change in shares held in trust (note 16 and 17)	(139)	159	–	(359)	–	(200)
Share-based payments (note 17)	–	–	–	850	–	850
Elimination of deficit (note 16)	–	(1,242,342)	–	–	1,242,342	–
Balance at December 31, 2019	**60,513**	**$ 96,876**	**$ 923**	**$ 44,234**	**$ (94,015)**	**$ 48,018**

See accompanying notes to the consolidated financial statements.

PERPETUAL ENERGY INC.
Consolidated Statements of Cash Flows

For the year ended	**December 31, 2020**	December 31, 2019
(*Cdn$ thousands*)		
Cash flows from (used in) operating activities		
Net loss	**$ (61,597)**	$ (94,015)
Adjustments to add (deduct) non-cash items:		
Other income (note 14(a))	**(812)**	–
Depletion and depreciation (note 5 and 7)	**15,533**	31,188
Exploration and evaluation (note 6)	**529**	1,599
Share-based payments (note 17)	**517**	406
Unrealized change in fair value of derivatives (note 21)	**(9,901)**	21,893
Change in fair value of TOU share investment (note 4)	**904**	3,207
Restructuring costs (note 14b)	**–**	1,546
Finance expense (note 19)	**5,244**	2,671
Impairment (note 5(b) and 6)	**42,500**	47,052
Oil and natural gas revenue in-kind (note 12)	**(2,319)**	–
Decommissioning obligations settled (note 14(a))	**(210)**	(1,733)
Payments of restructuring costs (note 14(b))	**(936)**	(610)
Change in non-cash working capital (note 20)	**1,015**	4,602
Net cash flows from (used in) operating activities	**(9,533)**	17,806
Cash flows used in financing activities		
Change in revolving bank debt, net of issue costs (note 9)	**(30,483)**	4,792
Change in TOU share margin demand loan, net of issue costs	**(100)**	(14,044)
Change in senior notes, net of issue costs (note 11)	**(549)**	(33)
Net proceeds from dispositions (note 5(a))	**6,996**	–
Payments of lease liabilities (note 13)	**(552)**	(441)
Payments of gas over bitumen royalty financing (note 12)	**(704)**	(1,013)
Shares purchased and held in trust (note 16(b))	**–**	(200)
Net cash flows used in financing activities	**(25,392)**	(10,939)
Cash flows from (used in) investing activities		
Capital expenditures	**(5,939)**	(12,939)
Acquisitions (note 5)	**(222)**	–
Net proceeds from dispositions (note 5(a))	**27,754**	–
Proceeds from sale of TOU share investment (note 4)	**14,316**	9,705
Change in non-cash working capital (note 20)	**(984)**	(3,633)
Net cash flows from (used in) investing activities	**34,925**	(6,867)
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 an oil and natural gas exploration, production and marketing company headquartered in Calgary, Alberta. Perpetual owns a diversified asset portfolio, including liquids-rich conventional natural gas assets in the deep basin of West Central Alberta, heavy crude oil and shallow conventional natural gas in Eastern Alberta, and undeveloped bitumen leases in Northern Alberta.

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 Alberta.

Future operations

Perpetual has a first lien, reserve-based credit facility (the "Credit Facility") (note 9). 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 share investment for net cash proceeds of $14.3 million. Net proceeds were used to repay the outstanding TOU share margin demand loan of $0.1 million, with the balance applied to the Credit Facility. On April 1, 2020, the Company sold a 50% working interest in its East Edson property in West Central Alberta to a third party (the "Purchaser") for consideration including a cash payment of $35 million and the carried interest funding of the drill, complete and tie-in costs for an eight well drilling program (the "East Edson Transaction") (note 5(a)). Net proceeds were used to repay a portion of the Credit Facility. Effective April 1, 2020, Perpetual's syndicate of Credit Facility lenders completed their borrowing base redetermination, incorporating the impact of the East Edson Transaction. The Borrowing Limit was reduced from $45 million to $20 million. As at December 31, 2020, $17.5 million was borrowed and $0.9 million of letters of credit were issued on the Credit Facility. The next Borrowing Limit redetermination, and maturity date, is scheduled to be completed by March 1, 2021. If not extended by March 1, 2021, the Credit Facility will cease to revolve, and all outstanding advances will be repayable. The semi-annual interest payment of $1.8 million that was payable December 31, 2020, was deferred by the Company's term loan lender and added to the principal amount owing as a condition of the Credit Facility lenders agreeing to extend the Credit Facility maturity to March 1, 2021. The further 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 (the "Term Loan") and deferred interest that matures and requires repayment on March 14, 2021 (note 10). The Company remains dependent on the support of its lenders to extend approaching maturities.

During the year ended December 31, 2020, there was a dramatic decline in oil, natural gas, and natural gas liquids ("NGL") commodity prices due to local and global supply and demand imbalances and the COVID-19 pandemic. This contributed to a net working capital deficiency (accounts payable and accrued liabilities, less accounts receivable and prepaid expenses and deposits) of $7.1 million as at December 31, 2020 and a $9.5 million use of cash from operations for the year then ended. The Company will require additional financing to fund the net working capital deficiency and future operations, and to refinance the upcoming Credit Facility and Term Loan maturities as the available liquidity and operating cash flows are not anticipated to be sufficient. In January 2021, the Company exchanged its $33.6 million 8.75% unsecured senior notes due January 23, 2022 for new $33.6 million 8.75% third lien senior notes due January 23, 2025 (the "New Senior Notes"). Interest on the New Senior Notes may be paid-in-kind at the option of the Company by adding the interest payment to the principal amount owing. On January 23, 2021 the $1.5 million semi-annual interest payment on the New Senior Notes was paid in kind (note 11). Although cash flows from operations are forecasted to improve for the next twelve-month period, Perpetual is considering other options including the extension of existing debt maturity dates, alternative financing, and the sale or monetization of additional assets.

Due to the facts and circumstances detailed above, coupled with considerable economic instability and uncertainty in the oil and gas industry 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 the Company's ability to manage its capital structure. As a result, there is 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 meet its obligations as they come due. Therefore, the Company 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 February 24, 2021.

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), royalty obligation (note 12) and derivative financial instruments (note 21) 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 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

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

iii) Componentization

For the purposes of depletion, the Company allocates its oil and gas 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 ("E&E") expenditures

Costs associated with acquiring oil and gas licenses and exploratory drilling are accumulated as exploration and evaluation 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 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 and has recorded revenue and the associated expenses on a gross basis. In other cases, the Company has been determined to be the agent and has recorded revenue net of associated expenses.

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 proved and probable oil and gas 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 oil, gas, and NGL reserves and their related cash flows are based upon a number of significant assumptions, such as forecasted production volumes, oil and gas commodity prices, operating costs, royalty costs, and future development costs. Additional estimates are made in relation to the marketability of oil and gas, and the assumed effects of regulation by government agencies. 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 gas properties, the calculation of depletion and depreciation, and the timing of decommissioning expenditures.

Independent third-party reserve evaluators are engaged at least annually to estimate proved and probable oil and gas reserves and the related cash flows from the Company's interest in oil and gas properties. This evaluation of proved and proved plus probable oil and gas reserves is prepared in accordance with the reserve definitions contained in National Instrument 51-101 and the COGE Handbook.

The Company is also required to estimate the recoverable amount of exploration and evaluation assets, which consists of undeveloped lands, exploratory drilling assets and bitumen evaluation assets, for impairment testing. The recoverable amount is based on relevant industry sales value data.

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 forecasted 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) Royalty obligations

The retained East Edson royalty obligation and the gas over bitumen royalty financing are measured at fair value on each reporting date. The fair value is estimated by discounting future cash payments based on the forecasted natural gas and NGL commodity prices multiplied by the remaining royalty obligation volumes. Changes in market pricing between period end and settlement could have a material impact on financial results related to the royalty obligations.

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.

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 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) Financial instruments

Financial instruments comprise accounts receivable, prepaid expenses and deposits, 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, royalty obligations, 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.

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, prepaid expenses and deposits, 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 royalty obligations 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 FVTPL. 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.

c) Property, plant and equipment ("PP&E")

i) Production and development costs

Items of property, plant and equipment, which include oil and 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 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 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. Proceeds may include cash, or other non-cash consideration such as retained drilling rights which are fair valued at the time of disposition. 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 oil and gas 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 oil and gas 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 third-party reserve evaluators 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.

d) Exploration and evaluation 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 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 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 lands, 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.

e) Right-of-use assets

The Company recognizes right-of-use assets and lease liabilities at the lease commencement date. The assets are measured at the lease liability initially recognized, which comprise the present value of the future lease payments 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. The Company presents right-of-use assets as its own line item on the consolidated statements of financial position. In determining the lease term, 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. 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 two and five years.

f) Lease liabilities

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, which is determined 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.

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. The Company presents lease liabilities as their own line item on the consolidated statements of financial position.

g) 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.

h) 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 consolidated statements 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 are any internal or external indicators of impairment or impairment reversal. If any such indicator exists, then the recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together at a CGU level. The estimated 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 the future cash flows expected to be derived from production of proved and probable oil and gas reserves estimated by the Company's independent third-party reserve evaluators.

An impairment is recognized if the carrying amount of a CGU exceeds the estimated recoverable amount for that CGU. The Company determines the estimated recoverable amount by using the greater of FVLCD and the VIU. 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.

E&E assets are assessed for impairment at the time that any triggering facts and circumstances suggest that the carrying amount exceeds the estimated recoverable amount as well as upon their eventual reclassification to oil and 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 estimated recoverable amount of the CGUs and E&E assets at the total company level is sufficient to cover the combined carrying value of the CGUs and E&E assets.

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.

i) 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 accounts payable and accrued liabilities, as a variable number of equity units will be required to settle the liability.

j) 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 consolidated statements of financial position (note 16(b)). 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.

k) 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 obligation 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 reporting 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 and can no longer withdraw the offer of those benefits. 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. The provision is measured on initial recognition at the Company's best estimate of the expenditure required to settle the obligation.

l) Revenue

Revenue from the sale of heavy crude oil, conventional 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.

If the consideration promised in a contract includes a variable amount, the Company estimates the amount of consideration to which it will be entitled in exchange for transferring the promised goods or services to a customer. Royalty obligations (note 12) are considered to be variable consideration that will be remeasured at fair value at each reporting date.

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.

m) 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.

n) 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 rights, 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, performance share rights and deferred compensation awards. 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.

o) Government grants

Government grants are recognized when there is reasonable assurance that the grant will be received, and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as an expense reduction in the period in which the costs are incurred. Government grants related to income are recorded as other income in the period in which eligible expenses were incurred or when the services have been performed. During the year ended December 31, 2020, the Company received government grants through the Canada Emergency Wage Subsidy ("CEWS") and Canada Emergency Rent Subsidy ("CERS") of $1.3 million (2019 – nil). For the year ended December 31, 2020, the grants were recognized as a reduction to general and administrative and production and operating expenses of $1.0 million and $0.3 million, respectively (2019 – nil and nil).

The Company also received government grant funding pursuant to Alberta's Site Rehabilitation Program ("SRP") with respect to approved abandonment and reclamation expenditures incurred by the Company. SRP funding of $0.8 million was received in 2020 (2019 – nil) and has been reported as other income (note 14(a)).

4. TOURMALINE OIL CORP. SHARE INVESTMENT

	December 31, 2020		December 31, 2019	
	Shares *(thousands)*	**Amount *($thousands)***	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of year	**1,000**	**$ 15,220**	1,656	$ 28,132
Sold	**(1,000)**	**(14,316)**	(656)	(9,705)
Unrealized change in fair value	**–**	**(904)**	–	(3,207)
Balance, end of year	**–**	**$ –**	1,000	$ 15,220

During the year ended December 31, 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. Proceeds were used to repay the $0.1 million TOU share margin demand loan in full and to pay down a portion of the revolving bank debt (note 9). Net loss for the year ended December 31, 2020 included an unrealized loss of $0.9 million (2019 – unrealized loss of $3.2 million) representing the change in fair value of TOU shares held during the period.

5. PROPERTY, PLANT AND EQUIPMENT

	Oil and Gas Properties	Corporate Assets	Total
Cost			
December 31, 2018	$ 719,201	$ 7,614	$ 726,815
Additions	12,201	74	12,275
Change in decommissioning obligations related to PP&E (note 14(a))	(1,211)	–	(1,211)
Transfers from exploration and evaluation (note 6)	1,335	–	1,335
December 31, 2019	$ 731,526	$ 7,688	$ 739,214
Additions	5,884	(36)	5,848
Drilling program rights (a)	18,000	–	18,000
Acquisitions	222	–	222
Change in decommissioning obligations related to PP&E (note 14(a))	2,747	–	2,747
Transfers from exploration and evaluation (note 6)	252	–	252
Dispositions (a)	(193,672)	–	(193,672)
December 31, 2020	**$ 564,959**	**$ 7,652**	**$ 572,611**
Accumulated depletion, depreciation and impairment			
December 31, 2018	$ (459,469)	$ (7,255)	$ (466,724)
Depletion and depreciation	(30,628)	(176)	(30,804)
Impairment (b)	(47,052)	–	(47,052)
December 31, 2019	$ (537,149)	$ (7,431)	$ (544,580)
Depletion and depreciation	(14,926)	(136)	(15,062)
Impairment (b)	(32,300)	–	(32,300)
Dispositions (a)	143,316	–	143,316
December 31, 2020	**$ (441,059)**	**$ (7,567)**	**$ (448,626)**
Carrying amount			
December 31, 2019	$ 194,377	$ 257	$ 194,634
December 31, 2020	**$ 123,900**	**$ 85**	**$ 123,985**

At December 31, 2020, property, plant and equipment included $1.0 million (December 31, 2019 – $1.9 million) of costs currently not subject to depletion.

For the year ended December 31, 2020, $0.2 million (December 31, 2019 – $0.4 million) of direct general and administrative expenses were capitalized. Future development costs for the year ended December 31, 2020 of $112.5 million (December 31, 2019 – $358.8 million) were included in the depletion calculation.

a) Dispositions

On April 1, 2020, the Company sold a 50% working interest in its East Edson property in West Central Alberta to the Purchaser. The consideration received, and calculation of the gain (loss) recorded on disposition is summarized below:

($ thousands)	
Cash proceeds from disposition (i)	**34,750**
Drilling program rights received (ii)	**18,000**
Retained East Edson royalty obligation (iii)	**(6,996)**
Carrying amount of PP&E and E&E disposed (iv)	**(52,803)**
Carrying amount of decommissioning obligations disposed (v)	**7,049**
Gain (loss) on disposition	**–**

i) Cash proceeds from disposition — $35.0 million of cash received on closing, net of $0.2 million of transaction costs and closing adjustments. In order to reflect the nature of the proceeds received, cash proceeds from disposition have been allocated on the consolidated statements of cash flows to financing and investing activities in the amount of $7.0 million and $27.8 million, respectively.

ii) Drilling program rights received — $18.0 million of drilling program rights, comprised of the carried interest funding of the drill, complete, and tie-in costs for an eight-well drilling program. Five horizontal wells targeting development of the Wilrich formation were drilled, completed and commenced production during the 2020 fiscal year. Drilling program rights have been subject to depletion. The Purchaser is required to fulfill its entire commitment by April 1, 2022 and will be obligated to pay Perpetual $2.25 million for each commitment well not completed and having commenced production by this time.

iii)	Retained East Edson royalty obligation	$7.0 million that Perpetual will retain until December 31, 2022 on behalf of the Purchaser, comprising the fair value of the Purchaser's 50% working interest in the existing gross overriding royalty on the East Edson property equivalent to 2.8 MMcf/d of conventional natural gas and associated NGL production (note 12).
iv)	Carrying amount of PP&E and E&E disposed	$52.8 million of oil and gas properties ($50.4 million) and exploration and evaluation assets ($2.4 million).
v)	Carrying amount of decommissioning obligations disposed	$7.0 million of decommissioning obligations associated with oil and gas properties disposed.

b) Cash-generating units and impairment

In accordance with IFRS, the Company is required to assess when internal or external indicators of impairment or impairment reversal exist, and impairment testing is required. At December 31, 2020, the Company conducted an assessment of indicators of impairment and impairment reversal for all the Company's CGUs. In performing the assessment, management determined that the recovery in global oil and gas commodity prices, changing development plans, positive reserve revisions, and increasing economic stability and certainty in the oil and gas industry, all of which positively impacts operating cash flows, justified calculation of the estimated recoverable amount of the liquids-rich conventional natural gas assets and heavy crude oil assets which comprise the West Central CGU and Eastern Alberta CGU, respectively. The estimated recoverable amounts of the CGUs were determined using value-in-use based on the estimates of proved and probable oil and gas reserves and the related cash flows as evaluated by the Company's independent third party reserves evaluators at December 31, 2020, along with oil and gas commodity price estimates based on an average of three independent third party reserve evaluators, and an estimate of market discount rates between 12% and 25% to consider risks specific to the CGUs.

At December 31, 2020, the Company determined that the estimated recoverable amounts of the West Central CGU and Eastern Alberta CGU exceeded the carrying amounts of $81.2 million and $24.7 million, respectively. Accordingly, an aggregate non-cash impairment reversal of $18.0 million was included in net loss.

Forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators were used in the VIU calculations as at December 31, 2020:

Year	West Texas Intermediate ("WTI") Crude Oil *(US$/bbl)*	USD/CDN exchange rate *(US$/Cdn$)*	Alberta Heavy Crude Oil *(Cdn$/bbl)*	AECO Gas *(Cdn$/MMBtu)*	NYMEX Gas *(Cdn$/MMBtu)*
2021	47.17	0.768	39.87	2.78	3.69
2022	50.17	0.765	43.20	2.70	3.75
2023	53.17	0.763	46.86	2.61	3.80
2024	54.97	0.763	48.67	2.65	3.88
2025	56.07	0.763	49.65	2.70	3.95
2026	57.19	0.763	50.65	2.76	4.03
2027	58.34	0.763	51.67	2.81	4.11
2028	59.50	0.763	52.71	2.87	4.19
2029	60.69	0.763	53.76	2.92	4.28
2030	61.91	0.763	54.84	2.98	4.36
2031	63.15	0.763	55.94	3.04	4.45
2032	64.41	0.763	57.05	3.10	4.54
2033	65.70	0.763	58.20	3.16	4.63
2034	67.01	0.763	59.36	3.23	4.72
2035(1)	68.35	0.763	60.55	3.29	4.81

(1) Forecasted oil and gas commodity prices escalate 2.0% per year thereafter.

As at December 31, 2020, if discount rates used in the calculation of impairment changed by 1% with all other variables held constant, the impairment reversal for the West Central CGU and Eastern Alberta CGU would change by approximately $3.4 million and $1.2 million, respectively. As at December 31, 2020, if forecasted oil and gas commodity prices changed by 5% with all other variables held constant, the impairment reversal for the West Central CGU and Eastern Alberta CGU would change by approximately $8.9 million and $6.0 million, respectively.

At March 31, 2020, the Company also conducted an assessment of internal and external indicators of impairment for all the Company's CGUs. In performing the assessment, management determined that the significant decline in global oil and gas commodity prices that was experienced following the onset of the COVID-19 pandemic, coupled with the considerable economic instability and uncertainty in the oil and gas industry which negatively impacts operating cash flows, justified calculation of the estimated recoverable amount of the liquids-rich conventional natural gas assets and heavy crude oil assets which comprise the West Central CGU and Eastern Alberta CGU, respectively. The estimated recoverable amounts of the CGUs were determined using VIU based on the estimates of proved and probable oil and gas reserves and the related cash flows as evaluated by the Company's independent third party reserves evaluators at December 31, 2019 and updated by internal reserve evaluators to March 31, 2020, along with forecasted oil and gas commodity prices based on an average of three independent third party reserve evaluators, and an estimate of market discount rates between 12% and 25% to consider risks specific to the CGUs.

At March 31, 2020, the Company determined that the carrying amounts of the West Central CGU and Eastern Alberta CGU exceeded the estimated recoverable amounts of $66.3 million and $26.4 million, respectively. Accordingly, an aggregate non-cash impairment charge of $50.3 million was included in net loss.

For the year ended December 31, 2020, the Company has recorded an aggregate non-cash impairment charge of $32.3 million related to the CGUs in net loss (2019 – $47.1 million).

6. EXPLORATION AND EVALUATION

	December 31, 2020	December 31, 2019
Balance, beginning of year	**$ 23,609**	$ 25,879
Additions	**91**	664
Dispositions	**(2,447)**	–
Impairments	**(10,200)**	–
Non-cash exploration and evaluation expense	**(529)**	(1,599)
Transfers to property, plant and equipment	**(252)**	(1,335)
Balance, end of year	**$ 10,272**	$ 23,609

During the year ended December 31, 2020, $0.2 million (2019 – $0.2 million) in costs were charged directly to E&E expense in net loss.

During the year ended December 31, 2020, the Company and its President and Chief Executive Officer ("CEO") acquired undeveloped lands from third parties in its Eastern Alberta core area. The Company has the option, but not the obligation, to acquire the CEO's interest in the acquired lands for an amount based on pre-determined parameters, prior to July 1, 2021.

Impairment of E&E assets

E&E assets are tested for impairment both at the time of any triggering facts and circumstances as well as upon their eventual reclassification to oil and gas properties in PP&E.

As at December 31, 2020, the Company conducted an assessment of internal and external indicators of impairment and impairment reversal for the Company's E&E assets. In performing the assessment, management determined that the recovery in global oil and gas commodity prices, changing development plans, positive revisions to reserves, and increasing economic stability and certainty in the oil and gas industry, all of which positively impacts operating cash flows, justified calculation of the estimated recoverable amount of E&E assets. As a result of this calculation, the Company determined that there was no non-cash impairment charge or impairment reversal to record.

As at March 31, 2020, management determined that the significant decline in global oil and gas commodity prices, coupled with the considerable economic instability and uncertainty in the oil and gas industry, justified calculation of the estimated recoverable amount of E&E assets. As a result of this calculation, the carrying value of the E&E assets was written down to the estimated recoverable amount, resulting in a non-cash impairment charge of $10.2 million (2019 – nil).

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
Additions	93	189	86	368
December 31, 2020	**$ 1,591**	**$ 389**	**$ 247**	**$ 2,227**
Accumulated depreciation				
January 1, 2019	$ –	$ –	$ –	$ –
Depreciation	(240)	(80)	(64)	(384)
December 31, 2019	$ (240)	$ (80)	$ (64)	$ (384)
Depreciation	(257)	(135)	(79)	(471)
December 31, 2020	**$ (497)**	**$ (215)**	**$ (143)**	**$ (855)**
Carrying amount				
December 31, 2019	$ 1,258	$ 120	$ 97	$ 1,475
December 31, 2020	**$ 1,094**	**$ 174**	**$ 104**	**$ 1,372**

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 (the "Trustee") 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 four-year-old transaction when, on October 1, 2016, Perpetual closed the disposition of shallow natural gas assets in Eastern Alberta 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.

On January 13, 2020, 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 conventional natural gas assets in Eastern Alberta to an unrelated third party on October 1, 2016 (the "Sequoia Disposition"). 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 the Trustee against Perpetual. The Court did not find that the test for summary dismissal relating to whether the asset 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, challenging the entire decision, and Perpetual filed a similar notice of appeal contesting the BIA claim portion of the decision (the "First Appeal"). The First Appeal proceedings were heard on December 10, 2020.

On February 25, 2020, Perpetual filed a second 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 asset transaction nor caused to be insolvent by the asset transaction. In July 2020, the Orphan Well Association ("OWA"), certain oil and gas companies, and six municipalities applied to intervene in the second BIA dismissal application proceedings. The OWA and certain oil and gas companies were permitted to intervene (the "Intervenors") in the proceedings which took place on October 1st and 2nd, 2020. The Intervenors were also permitted to intervene in the First Appeal proceedings.

On January 14, 2021 the Court found that PwC could not establish a necessary element of the BIA Claim as Sequoia was not insolvent at the time of, nor rendered insolvent by, the Sequoia Disposition. The Court therefore concluded there is "no merit" to the BIA Claim and it summarily dismissed the balance of the Statement of Claim. PwC has subsequently appealed this decision (the "Second Appeal").

On January 25, 2021, the Court of Appeal of Alberta issued their decision with respect to the First Appeal proceedings. The decision dismissed the appeal filed by Perpetual and granted certain aspects of the appeal filed by PwC, reinstating certain elements of the Sequoia Litigation for trial.

Management expects that the Company is more likely than not to be completely 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 these financial statements.

9. REVOLVING BANK DEBT

As at December 31, 2020, the Company's Credit Facility had a Borrowing Limit of $20.0 million (December 31, 2019 – $55.0 million) under which $17.5 million was drawn (December 31, 2019 – $47.6 million) and $0.9 million of letters of credit had been issued (December 31, 2019 – $2.3 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%. The effective interest rate on the Credit Facility at December 31, 2020 was 6.95%. For the period ended December 31, 2020, if interest rates changed by 1% with all other variables held constant, the impact on annual cash finance expense and net loss would be $0.2 million.

Effective April 1, 2020, Perpetual's syndicate of Credit Facility lenders completed their borrowing base redetermination, incorporating the impact of the East Edson Transaction. The Borrowing Limit was reduced from $45 million to $20 million. The next Borrowing Limit redetermination, and current maturity date, is scheduled to be completed by March 1, 2021. If not extended by March 1, 2021, the Credit Facility will cease to revolve, and all outstanding advances will be repayable. As a result, revolving bank debt has been presented as a current liability on the consolidated statements of financial position as at December 31, 2020. Previously, 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.

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 Term Loan and Senior Note principal and interest and to pay dividends on or repurchase its common shares.

At December 31, 2020, the Credit Facility was not subject to any additional financial covenants and the Company was in compliance with all customary non-financial covenants.

10. TERM LOAN

			December 31, 2020		December 31, 2019	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
Term Loan	March 14, 2021	8.1%	**$ 46,823**	**$ 46,691**	$ 45,000	$ 44,274

The Term Loan bears a fixed interest rate of 8.1% with semi-annual interest payments due June 30th and December 31st of each year. In the fourth quarter of 2020, the Company and lender reached an agreement, allowing outstanding interest amounts of $1.8 million related to the December 31st payment to be paid-in-kind and added to the outstanding principal amount of the loan.

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 matures and is repayable on March 14, 2021 and has been presented as a current liability on the consolidated statements of financial position as at December 31, 2020.

The Term Loan has a cross-default provision with the Credit Facility and contains substantially similar provisions and covenants as the Credit Facility (note 9). The Term Loan is secured by a general security agreement over all present and future property of the Company and its subsidiaries on a second priority basis, subordinate only to liens securing loans under the Credit Facility, and certain lands pledged to the gas over bitumen royalty financing counterparty (note 12).

At December 31, 2020 the Term Loan is presented net of $0.1 million in issue costs which are amortized over the remaining term of the loan using a weighted average effective interest rate of 9.2%.

At December 31, 2020, the Term Loan was not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

11. SENIOR NOTES

			December 31, 2020		December 31, 2019	
	Maturity date	**Interest rate**	**Principal**	**Carrying Amount**	Principal	Carrying amount
2022 Senior Notes	January 23, 2022	8.75%	**33,580**	**32,359**	33,580	32,255

The 2022 Senior Notes bear a fixed interest rate of 8.75% with semi-annual interest payments due January 23rd and July 23rd 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. The Company may redeem the senior notes without any repayment penalty.

At December 31, 2020, the 2022 Senior Notes are recorded at the present value of future cash flows, net of $1.2 million in issue and principal discount costs which are amortized over the remaining term using a weighted average effective interest rate of 12.4%.

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, 2020, the senior notes were not subject to any financial covenants and the Company was in compliance with all customary non-financial covenants.

Entities controlled by the Company's CEO hold $14.6 million of the 2022 Senior Notes outstanding. An entity that is associated with the Company's CEO holds an additional $9.1 million of the 2022 Senior Notes outstanding.

On January 22, 2021, Perpetual announced the completion of a Court-approved plan of arrangement whereby the 2022 Senior Notes were exchanged for new 8.75% secured third lien notes due January 23, 2025 (the "2025 Senior Notes"). The 2025 Senior Notes have been issued under a trust indenture that contains substantially the same terms as the 2022 Senior Notes, other than the 2025 Senior Notes are secured on a third lien basis and allow for the semi-annual interest payments to be paid at Perpetual's option, in either cash, or in additional 2025 Senior Notes (a "PIK Interest Payment"). The Company elected to pay the January 23, 2021 interest payment of $1.5 million by a PIK Interest Payment which increased the principal amount of the 2025 Senior Notes outstanding to $35.0 million.

12. ROYALTY OBLIGATIONS

	Retained East Edson royalty obligation	**Gas over bitumen royalty financing**	**Total**
December 31, 2018	–	1,152	1,152
Cash payments	–	(1,013)	(1,013)
Change in fair value	–	732	732
December 31, 2019	–	871	871
Initial recognition (note 5(a))	6,996	–	6,996
Cash payments	–	(704)	(704)
Non-cash payments in-kind	(2,319)	–	(2,319)
Change in fair value (note 19)	1,037	268	1,305
December 31, 2020	**5,714**	**435**	**6,149**

	December 31, 2020	December 31, 2019
Current	**$ 3,553**	$ 582
Non-current	**2,596**	289
Total royalty obligations	**$ 6,149**	$ 871

The retained East Edson royalty obligation formed part of the net consideration received by Perpetual from the East Edson Transaction whereby Perpetual agreed to retain the Purchaser's 50% working interest in the existing gross overriding royalty obligation on the property, equivalent to 2.8 MMcf/d of natural gas and associated NGL production for the period April 1, 2020 to December 31, 2022 (see note 5(a)(iii)). The retained East Edson royalty obligation is paid in-kind, and settled through non-cash delivery of contractual natural gas and NGL volumes to the royalty holder (note 18).

The Company has designated the retained East Edson royalty obligation and the gas over bitumen royalty financing as financial liabilities which are measured at fair value through profit and loss, estimated by discounting future royalty obligations based on forecasted natural gas and NGL commodity prices multiplied by the royalty obligation volumes. For the year ended December 31, 2020, an unrealized loss of $1.3 million (2019 – unrealized loss of $0.7 million) is included in non-cash finance expense related to the change in fair value of total royalty obligations (note 19).

As at December 31, 2020, if forecasted natural gas commodity prices changed by $0.25 per GJ with all other variables held constant, the fair value of the total royalty obligations and net loss for the period would change by $0.6 million.

13. LEASE LIABILITIES

	December 31, 2020	December 31, 2019
Balance, beginning of year	**$ 2,685**	$ 3,126
Additions	**368**	–
Interest on lease liabilities (note 19)	**175**	189
Payments	**(727)**	(630)
Total lease liabilities	**$ 2,501**	$ 2,685
Current	**$ 710**	$ 633
Non-current	**1,791**	2,052
Total lease liabilities	**$ 2,501**	$ 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 ended December 31, 2020, the Company recognized $0.1 million (2019 – $0.2 million) of short-term, low value, and variable lease costs directly in net loss.

14. PROVISIONS

The components of provisions are as follows:

	December 31, 2020	December 31, 2019
Decommissioning obligations (a)	**$ 33,024**	$ 37,905
Restructuring costs (b)	**–**	936
Total provisions	**$ 33,024**	$ 38,841
Current	**$ 1,048**	$ 2,382
Non-current	**31,976**	36,459
Total provisions	**$ 33,024**	$ 38,841

a) Decommissioning obligations

The following table summarizes changes in decommissioning obligations:

	December 31, 2020	December 31, 2019
Obligations incurred, including acquisitions	**$ 603**	$ 327
Change in risk free interest rate	**2,344**	(1,900)
Change in estimates	**(200)**	362
Change in decommissioning obligations related to PP&E (note 5)	**2,747**	(1,211)
Obligations settled (cash)	**(210)**	(1,733)
Obligations settled[1] (non-cash)	**(812)**	–
Obligations disposed (note 5(a)(v))	**(7,049)**	–
Accretion (note 19)	**443**	752
Change in decommissioning obligations	**(4,881)**	(2,192)
Balance, beginning of year	**37,905**	40,097
Balance, end of year	**$ 33,024**	$ 37,905
Current	**$ 1,048**	$ 1,446
Non-current	**31,976**	36,459
Total decommissioning obligations	**$ 33,024**	$ 37,905

(1) Obligations settled (non-cash) of $0.8 million (2019 – nil) were funded by payments made directly to Perpetual's service providers from the Alberta Site Rehabilitation Program. These amounts have been recorded as other income.

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 increase in the provision due to the passage of time, which is referred to as accretion, is recognized as non-cash finance expense in the consolidated statements of loss and comprehensive loss. Decommissioning obligations are further adjusted at each period end date for changes in the risk-free interest rate, after considering additions and dispositions of PP&E. Decommissioning obligations are also adjusted for revisions to future cost estimates and the estimated timing of costs to be incurred in future periods.

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

	December 31, 2020	December 31, 2019
Undiscounted obligations	**$ 31,683**	$ 40,304
Average risk-free rate	**1.2%**	1.8%
Inflation rate	**1.5%**	1.3%
Expected timing of settling obligations	**1 to 25 years**	1 to 25 years

b) Restructuring costs

	Employee downsizing costs	**Lease inducement**	**Total**
December 31, 2018	–	1,267	1,267
Lease inducement transferred to lease liability	–	(1,267)	(1,267)
Initial recognition	1,546	–	1,546
Payments	(610)	–	(610)
December 31, 2019	936	–	936
Payments	(936)	–	(936)
December 31, 2020	**–**	**–**	**–**

In response to the decrease in forecasted oil and gas commodity prices, the Company implemented a restructuring plan in the third quarter of 2019, which resulted in the reduction of its corporate employee head count by approximately 25%. Restructuring costs of $1.5 million were expensed into net loss and were fully paid by the end of 2020. Payments made in 2020 with respect to restructuring costs were $0.9 million (2019 – $0.6 million).

15. CONTRACTUAL OBLIGATIONS

As at December 31, 2020, the Company's minimum contractual obligations and lease commitments over the next five years and thereafter, excluding estimated interest payments, are as follows:

	2021	**2022**	**2023**	**2024**	**2025 and thereafter**	**Total**
Contractual obligations						
Accounts payable and accrued liabilities	11,924	–	–	–	–	11,924
Fair value of derivative liabilities	3,373	–	–	–	–	3,373
Revolving bank debt	17,495	–	–	–	–	17,495
Term loan, principal amount	46,823	–	–	–	–	46,823
Senior notes, principal amount[1]	–	33,580	–	–	–	33,580
Royalty obligations	3,553	2,596	–	–	–	6,149
Lease liabilities	710	659	541	477	114	2,501
Pipeline transportation commitments	1,416	1,278	1,001	1,001	1,001	5,697
Total	**85,294**	**38,113**	**1,542**	**1,478**	**1,115**	**127,542**

(1) The 2025 Senior Notes issued subsequent to year end under the Court approved plan of arrangement will become due January 23, 2025 (note 11).

16. SHARE CAPITAL

	December 31, 2020		December 31, 2019	
	Shares *(thousands)*	**Amount *($thousands)***	Shares *(thousands)*	Amount *($thousands)*
Balance, beginning of year	**60,513**	**$ 96,876**	60,240	$ 1,338,369
Issued pursuant to share-based payment plans	**548**	**340**	412	690
Shares held in trust purchases (b)	**–**	**–**	(756)	(200)
Shares held in trust issued (b)	**244**	**117**	617	359
Elimination of deficit	**–**	**–**	–	(1,242,342)
Balance, end of year	**61,305**	**$ 97,333**	60,513	$ 96,876

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 17). 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, 2020, 0.6 million shares were held in trust (December 31, 2019 – 0.8 million).

c) Warrants

The following table summarizes the warrants issued:

	Warrants (*thousands*)	Amount (*$thousands*)
Balance, December 31, 2018	6,480	$ 923
Exercised for common shares	–	–
Balance, December 31, 2019	6,480	$ 923
Exercised for common shares	–	–
Expired	(6,480)	(923)
Balance, December 31, 2020	**–**	**$ –**

On March 14, 2020, the warrants expired unexercised. The value attributed to the warrants was transferred to contributed surplus.

d) Per share information

For the year ended	**December 31, 2020**	December 31, 2019
(*thousands, except per share amounts*)		
Net loss – basic	**$ (61,597)**	$ (94,015)
Effect of dilutive securities	**–**	–
Net loss – diluted	**$ (61,597)**	$ (94,015)
Weighted average shares		
Issued common shares	**61,577**	61,107
Effect of shares held in trust	**(564)**	(849)
Weighted average common shares outstanding – basic and diluted	**61,013**	60,258
Net loss per share – basic and diluted	**$ (1.01)**	$ (1.56)

In computing per share amounts for the year ended December 31, 2020, 16.3 million potentially issuable common shares through the share-based payment plans and warrants (2019 – 18.7 million) were excluded as the Company had a net loss.

17. SHARE-BASED PAYMENTS

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

	December 31, 2020	December 31, 2019
Compensation awards	**$ 155**	$ 365
Share options	**216**	452
Performance share rights	**1,646**	1,478
Share-based payment expense	**$ 2,017**	$ 2,295

The following tables summarize information about options, rights, and awards outstanding:

	Compensation awards					
(thousands)	**Deferred options**	**Deferred shares**	**Share options**	**Performance share rights**	**Restricted rights**	**Total**
December 31, 2018	4,165	1,947	4,724	1,465	–	12,301
Granted	–	253	–	1,710	423	2,386
Exercised for common shares	–	–	–	–	(412)	(412)
Exercised for shares held in trust	–	(617)	–	–	–	(617)
Exercised for restricted rights	–	(208)	–	(215)	–	(423)
Performance adjustment	–	–	–	(215)	–	(215)
Cancelled/forfeited	(577)	(99)	(120)	–	(11)	(807)
Expired	(1)	–	–	–	–	(1)
December 31, 2019	3,587	1,276	4,604	2,745	–	12,212
Granted	2,250	1,571	873	1,710	557	6,961
Exercised for common shares	–	–	–	–	(548)	(548)
Exercised for shares held in trust	–	(244)	–	–	–	(244)
Exercised for restricted rights	–	(40)	–	(517)	–	(557)
Performance adjustment	–	–	–	(518)	–	(518)
Cancelled/forfeited	(754)	(162)	–	–	(9)	(925)
Expired	(26)	–	(80)	–	–	(106)
December 31, 2020	**5,057**	**2,401**	**5,397**	**3,420**	**–**	**16,275**

During the year ended December 31, 2020, the Company granted 6.4 million share-based payment awards, comprised of deferred options, deferred shares, share options, and performance share rights (2019 – 1.9 million). The Company used the Black Scholes pricing model to calculate the estimated fair value of the outstanding deferred options (note 17(a)) and share options (note 17(b)) at the date of grant. The following assumptions were used to arrive at the estimate of fair value as at the date of grant:

	2020	2019
Dividend yield (%)	**0.0**	–
Forfeiture rate (%)	**5.0-10.0**	–
Expected volatility (%)	**60.0**	–
Risk-free interest rate (%)	**0.5**	–
Expected life (years)	**2.9-3.1**	–
Vesting period (years)	**4.0**	–
Contractual life (years)	**5.0**	–
Weighted average share price at grant date	**$ 0.07**	–
Weighted average fair value at grant date	**$ 0.03**	–

During the year ended December 31, 2020, 0.5 million restricted rights were issued in exchange for the exercise of performance share rights (2019 – 0.2 million) and a nominal amount of restricted rights were issued in exchange for the exercise of deferred shares (2019 – 0.2 million).

a) 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 16(b)).

The following table summarizes information about the deferred options and performance-based long-term incentive awards outstanding:

	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 $0.04	2,400	3.60	–	594	–
$0.05 to $0.84	1,514	3.74	0.14	300	0.25
$0.85 to $1.72	1,143	1.02	1.61	967	1.58
Total	5,057	3.06	0.41	1,861	0.86

There were no deferred options granted during the prior year.

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 17(d)), 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 16(b)).

The fair value of these awards 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% (2019 – 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 share price of deferred shares granted during the year ended December 31, 2020 was $0.07 per award (2019 – $0.20).

b) Share options

Perpetual's share option plan provides a long-term incentive to executive officers 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 table summarizes information about share options outstanding:

	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*)**
$0.07 to $1.29	1,777	3.6	0.18	462	0.31
$1.30 to $1.57	1,725	0.4	1.42	1,725	1.42
$1.58 to $1.72	1,895	1.4	1.72	1,440	1.72
Total	5,397	1.8	1.12	3,627	1.40

There were no share options granted during the prior year.

c) Performance share rights

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 17(d)), 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, 2020, performance multipliers of 0.5 have been assumed for those unvested awards granted in 2019 and 2020. 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% (2019 – 5%) for outstanding awards. The estimated weighted average share price of performance share rights granted during the year ended December 31, 2020 was $0.07 per award (2019 – $0.19).

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 17(d)), or a combination of cash and restricted rights.

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. In 2020, the Company made payments of $1.5 million (2019 – $1.5 million) pursuant to cash-settled share-based payment awards. As at December 31, 2020, $0.4 million had been accrued pursuant to cash-settled share-based compensation awards (December 31, 2019 – $0.4 million).

d) Restricted rights

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, 2020, 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 17(c)) vest on the grant date and have a 90-day exercise period. Restricted rights granted upon the exercise of deferred compensation awards (note 17(a)) 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.

18. 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 conventional natural gas, heavy 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.

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

For the year ended December 31, 2020, the Company had sales to two customers (2019 – three customers) which exceeded ten percent of oil and natural gas revenue. The first customer represented 31% and $9.0 million (2019 – 41% and $30.8 million) of oil and natural gas revenue, and included revenues of $1.0 million (2019 – $28.0 million) related to the market diversification contract below. The second customer represented 33% and $9.7 million (2019 – 15% and $11.2 million) of oil and natural gas revenue.

Natural gas volumes sold pursuant to the Company's market diversification contract are sold at fixed volume obligations and priced at daily index prices plus US$0.02/MMBtu until October 31, 2022 and less US$0.08/MMBtu thereafter, less transportation costs from AECO to each market price point as detailed below.

In the third quarter of 2019, the Company eliminated its market diversification contract obligations at five North American natural gas hub pricing points (Chicago, Malin, Dawn, Michcon, and Empress) for the period commencing December 1, 2019 and ending on October 31, 2020 in consideration for receipt of $2.7 million. The amount was recognized as a realized gain on derivatives (note 21).

In the third quarter of 2020, the Company reduced its fixed volume obligations by 30,000 MMBtu/d for the period commencing November 1, 2020 and ending on October 31, 2021 in consideration for the payment of $1.0 million over the term of the associated contract volumes. The amount has been recognized as a realized loss on derivatives (note 21).

In the fourth quarter of 2020, the Company reduced its fixed volume obligation by 14,600 MMBtu/d for the period commencing November 1, 2021 and ending on October 31, 2022 in consideration for the receipt of $0.5 million over the term of the associated contract volumes. The amount has been recognized as a realized gain on derivatives (note 21).

Market/Pricing Point	**November 1, 2020 to October 31, 2021 Daily sales volume *(MMBtu/d)***	**November 1, 2021 to October 31, 2022 Daily sales volume *(MMBtu/d)***	**November 1, 2022 to October 31, 2024 Daily sales volume *(MMBtu/d)***
Chicago	4,000	12,200	–
Malin	–	–	15,000
Dawn	6,000	8,000	15,000
Michcon	–	5,200	–
Empress	–	–	–
Emerson	–	–	10,000
Total natural gas sales volume obligation	**10,000**	**25,400**	**40,000**

Subsequent to December 31, 2020, the Company eliminated its fixed volume obligation for the period commencing April 1, 2021 and ending October 31, 2021 in consideration for the payment of $1.4 million over the term of the associated contract volumes.

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

	December 31, 2020	December 31, 2019
Oil and natural gas revenue		
Natural gas(1)(2)	**13,329**	39,318
Oil	**12,015**	23,958
NGL	**4,142**	11,085
Total oil and natural gas revenue	**29,486**	74,361

(1) Includes revenue related to the market diversification contract of $1.0 million for the year ended December 31, 2020 (2019 – revenue of $28.0 million). Also included are losses related to physical forward sales contracts which settled during of the period of $5.2 million for the year ended December 31, 2020 (2019 – gains of $0.7 million).

(2) For the year ended December 31, 2020, natural gas revenue includes $2.3 million (2019 – nil) of non-cash revenue taken in-kind related to production used in the settlement of the retained East Edson royalty obligation (note 12).

Included in accounts receivable at December 31, 2020 is $2.3 million of accrued oil and natural gas revenue related to December 2020 production (December 31, 2019 – $4.5 million related to December 2019 production).

19. FINANCE EXPENSE

The components of finance expense are as follows:

	December 31, 2020	December 31, 2019
Cash finance expense		
Interest on revolving bank debt	**$ 1,662**	$ 2,880
Interest on TOU share margin demand loan	**–**	407
Interest on term loan	**1,812**	3,645
Interest on senior notes	**2,938**	2,921
Interest on lease liabilities	**175**	189
Dividend income from TOU share investment	**–**	(762)
Total cash finance expense	**$ 6,587**	$ 9,280
Non-cash finance expense		
Interest paid in-kind (note 10)	**1,823**	–
Amortization of debt issue costs	**1,673**	1,187
Accretion on decommissioning obligations (note 14a)	**443**	752
Change in fair value of royalty obligations (note 12)	**1,305**	732
Total non-cash finance expense	**$ 5,244**	$ 2,671
Finance expenses recognized in net loss	**$ 11,831**	$ 11,951

20. CHANGES IN NON-CASH WORKING CAPITAL INFORMATION

For the year ended	**December 31, 2020**	December 31, 2019
Accounts receivable	**$ 1,103**	$ 3,875
Prepaid expenses and deposits	**282**	(16)
Accounts payable and accrued liabilities(1)	**(1,354)**	(2,890)
Change in non-cash working capital	**$ 31**	$ 969

(1) Includes $0.4 million (December 31, 2019 – $0.4 million) of cash-settled share-based payment awards (note 17).

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

For the year ended	**December 31, 2020**	December 31, 2019
Operating	**$ 1,015**	$ 4,602
Investing	**(984)**	(3,633)
Change in non-cash working capital	**$ 31**	$ 969

21. 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 natural 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 carrying amount of accounts receivable as at December 31, 2020 was $4.0 million (December 31, 2019 – $5.1 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, 2020 of $0.6 million (December 31, 2019 – $0.9 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 $0.6 million as at December 31, 2020 (December 31, 2019 – $0.8 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, 2020, 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 commodity prices.

Natural gas contracts

As at December 31, 2020, the Company had entered into various fixed price basis differential contracts between AECO and NYMEX for terms settling in 2021 that have been substantially locked-in by similar equal and offsetting arrangements having an aggregate fair value loss of $3.4 million.

Oil contracts

At December 31, 2020, the Company had entered into the following physical fixed price oil sales arrangements which settle in US$:

Term	**Volumes (*bbls/d*)**	**Western Canadian Select ("WCS") (US*$/bbl*)**	**Fair Value (*$ thousands*)**
January 2021	203	33.70	(16)
February 2021	337	31.05	(23)
March 2021	406	32.75	4

Term	**Volumes (*bbls/d*)**	**WTI (US*$/bbl*)**	**Fair Value (*$ thousands*)**
January 2021	203	44.05	(30)
January 2021 – March 2021	203	41.50	(156)

Term	Volumes (*bbls/d*)	WTI-WCS differential (*US$/bbl*)	Fair Value (*$ thousands*)
January 2021	203	(12.35)	(2)
April 2021 – September 2021	203	(14.20)	10
January 2021 – December 2021	310	(13.25)	191

Oil contracts - sensitivity analysis

As at December 31, 2020, if future WTI oil prices changed by US$5.00 per bbl with all other variables held constant, the fair value of derivatives and net loss for the period would change by $0.3 million.

As at December 31, 2020, if future WTI-WCS differential oil prices changed by US$5.00 per bbl with all other variables held constant, the fair value of derivatives and net loss for the period would change by $1.2 million.

The following table summarizes the fair value of derivative contracts by type:

	December 31, 2020	December 31, 2019
Physical natural gas contracts	**$ (3,351)**	$ (6,294)
Financial natural gas contracts	**–**	(4,302)
Physical oil contracts	**(22)**	–
Financial oil contracts	**–**	(2,253)
Financial NGL contracts	**–**	(351)
Financial foreign exchange contracts	**–**	(74)
Fair value of derivatives	**$ (3,373)**	$ (13,274)
Derivative liabilities – current	**(3,373)**	(10,542)
Derivative liabilities – non-current	**–**	(2,732)
Fair value of derivatives	**$ (3,373)**	$ (13,274)

The following table details the change in fair value of derivatives:

	December 31, 2020	December 31, 2019
Unrealized gain (loss) on physical natural gas contracts	**2,943**	(11,587)
Unrealized gain (loss) on financial natural gas contracts	**4,302**	(8,638)
Unrealized gain (loss) on physical oil contracts	**(22)**	–
Unrealized gain (loss) on financial oil contracts	**2,253**	(3,542)
Unrealized gain (loss) on financial NGL contracts	**351**	(351)
Unrealized gain (loss) on financial foreign exchange contracts	**74**	2,225
Unrealized change in fair value of derivatives	**9,901**	(21,893)
Realized gain (loss) on financial natural gas contracts[1]	**(6,619)**	3,917
Realized gain (loss) on financial oil contracts	**7,967**	(3,818)
Realized gain (loss) on financial NGL contracts	**(171)**	(328)
Realized gain (loss) on financial foreign exchange contracts	**(469)**	(560)
Change in fair value of derivatives	**10,609**	(22,682)

(1) Includes realized losses of $0.5 million (December 31, 2019 – realized gains of $2.7 million) from the modification of the market diversification contract for the November 1, 2020 to October 31, 2022 period.

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 forecasted commodity prices.

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, prepaid expenses and deposits, 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 royalty obligations is estimated by discounting future cash payments based on the forecasted natural gas and NGL commodity prices multiplied by the royalty volumes. This fair value measurement is classified as level 3 as significant unobservable inputs, including the discount rate and forecasted natural gas and NGL commodity prices, are used in determination of the carrying amount. Discount rates of 12.0% to 12.2% were determined on inception of the agreements based on the characteristics of the instruments.

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, 2020	**Gross**	**Netting[1]**	**Carrying Amount**	**Level 1**	**Level 2**	**Level 3**
Financial assets						
Fair value through profit and loss						
Fair value of derivatives	10,384	(10,384)	–	–	–	–
Financial liabilities						
Financial liabilities at amortized cost						
Revolving bank debt	(17,495)	–	(17,495)	(17,568)	–	–
Senior notes	(32,359)	–	(32,359)	–	(32,359)	–
Term loan	(46,691)	–	(46,691)	–	–	(46,822)
Fair value through profit and loss						
Fair value of derivatives	(13,757)	10,384	(3,373)	–	(3,373)	–
Royalty obligations	(6,149)	–	(6,149)	–	–	(6,149)

(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, 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)	–
Royalty obligations	(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.

22. 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 net loss before income tax. This difference results from the following items:

	December 31, 2020	December 31, 2019
Net loss before income tax	**$ (61,597)**	$ (94,015)
Combined federal and provincial tax rate	**24.0%**	26.5%
Computed income tax expense (recovery)	**(14,783)**	(24,914)
Increase (decrease) in income taxes resulting from:		
Non-deductible expenses	**127**	124
Non-taxable capital loss	**108**	425
Other	**526**	891
Change in tax losses applied	**7,395**	–
Change in tax rates and unrecognized tax assets	**6,627**	23,474
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, 2020**	December 31, 2019
Liabilities:		
Senior notes	**$ 281**	$ 351
Term loan	**30**	192
Right-of-use-assets	**315**	391
Total deferred income tax liabilities	**626**	934
Assets:		
Decommissioning obligations	**$ (626)**	$ (934)

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, 2020**	December 31, 2019
Non-capital losses	**$ 213,221**	$ 201,739
Capital losses	**227,346**	151,553
Property, plant and equipment	**80,025**	83,396
Decommissioning obligations	**30,299**	34,379
Fair value of derivatives	**3,373**	13,275
TOU share investment	–	13,261
Share and debt issue costs	**2,070**	2,813
Lease liabilities	**2,501**	2,686
Royalty obligations	**6,149**	871
Other	–	936
	$ 564,984	$ 504,909

As at December 31, 2020, the Company had approximately $213 million (December 31, 2019 - $202 million) of non-capital losses available for future use. The unused non-capital losses expire between 2036 and 2040, and unused capital losses have no expiry date. The oil and gas properties and facilities owned by the Company and its subsidiaries have an approximate tax basis of $214 million (December 31, 2019 – $256 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.

23. 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, 2020**	December 31, 2019
Short-term compensation	**$ 1,685**	$ 2,434
Share-based payments	**1,906**	1,987
	$ 3,591	$ 4,421

24. 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, 2020**	December 31, 2019
Production and operating	**$ 1,259**	$ 2,009
General and administrative	**3,963**	8,234
Share-based payments	**2,017**	2,295
Restructuring costs	**–**	1,546
	$ 7,239	$ 14,084

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][3][4]
Ryan A. Shay
Incoming Vice President, Finance and Chief Financial Officer[4]
Howard R. Ward
Independent Director[1][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[1]
Vice President, Finance and Chief Financial Officer
Ryan A. Shay
Incoming 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

(1) Mr. Schweitzer plans to retire in the spring of 2021

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McDaniel & Associates Consultants Ltd.

REGISTRAR AND TRANSFER AGENT

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