2020 Annual Results

Paramount Resources Ltd. Reports 2020 Annual Results and Provides 2021 Guidance

Calgary, Alberta – March 3, 2021

HIGHLIGHTS

- Annual sales volumes averaged 68,340 Boe/d (39% liquids) in 2020. Fourth quarter 2020 sales volumes averaged 73,460 Boe/d (42% liquids), ahead of guidance of 70,000 to 72,000 Boe/d.(1)
  - Fourth quarter sales volumes at Karr, which benefitted from bringing onstream the five-well 5-16 West pad in November, averaged 26,914 Boe/d (56% liquids), compared to 19,246 Boe/d (57% liquids) in the third quarter.
  - Fourth quarter sales volumes at Wapiti averaged 10,764 Boe/d (64% liquids), compared to 7,925 Boe/d (63% liquids) in the third quarter. The Company brought five new wells onstream on the 5-3 West pad during the fourth quarter.
- Cash from operating activities was $81 million in 2020 and $53 million in the fourth quarter. Adjusted funds flow in 2020 was $150 million or $1.12 per share. Fourth quarter 2020 adjusted funds flow was $68 million or $0.51 per share.(2)
- Capital spending in 2020 totaled $221 million, below guidance of $225 million. Fourth quarter 2020 capital spending was $65 million, resulting in free cash flow of $3 million in the quarter.(2)
- Abandonment and reclamation expenditures in 2020 totaled $35 million. In addition, approximately $4 million of activities were funded through government programs. Activities included the abandonment of 254 inactive wells, 236 of which were abandoned under the Company's ongoing area-based closure program at Hawkeye and Zama.
- Based on Paramount's strong financial and operational performance, in March 2021 the Company elected to exit the covenant relief period under its $1.0 billion bank credit facility prior to the scheduled expiry of the period on June 30, 2021.

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(1) In this press release, "liquids" refers to NGLs (including condensate) and oil combined, "natural gas" refers to conventional natural gas and shale gas combined, "condensate and oil" refers to condensate, light and medium crude oil and tight oil combined and "other NGLs" refers to ethane, propane and butane. See the Product Type Information section for a complete breakdown of sales volumes for applicable periods by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil. See also "Oil and Gas Measures and Definitions" in the Advisories section.

(2) "Adjusted funds flow" and "free cash flow" are Non-GAAP financial measures. See "Non-GAAP Financial Measures" in the Advisories section.

- The Company exceeded its previously announced 2020 cost reduction targets of $25 million in operating costs and $15 million in general and administrative expenses ("G&A").
  - Operating costs were $0.62/Boe lower in 2020 than in 2019, averaging $11.88/Boe in 2020. Fourth quarter operating costs were $11.80/Boe and included unbudgeted workovers on five wells in Karr, which partially contributed to fourth quarter production outperformance.
  - G&A costs were approximately $20 million ($0.43/Boe) lower in 2020 than in 2019, averaging $1.31/Boe in 2020.
- The Company successfully closed non-core asset dispositions for cash proceeds of approximately $80 million in the first quarter of 2021. The estimated impact to average 2021 production is approximately 2,600 Boe/d (15 MMcf/d of conventional natural gas and 135 Bbl/d of NGLs).

GRANDE PRAIRIE ACTIVITIES AND PERFORMANCE

- At Karr, a total of 15 new Montney wells were brought on production in the second half of 2020 following completion of an expansion to the third-party Karr 6-18 facility in July.
  - The five-well 12-18 pad and the five-well 2-1 pad were brought on production in the third quarter. These 10 wells averaged 1,502 Boe/d (3.6 MMcf/d of shale gas and 905 Bbl/d of NGLs) of peak 30-day wellhead production per well, with an average condensate to gas ratio ("CGR") of 253 Bbl/MMcf.(1)
  - The five-well 5-16 West pad was brought onstream in November 2020. These wells averaged 1,617 Boe/d (3.7 MMcf/d of shale gas and 1,002 Bbl/d of NGLs) of peak 30-day wellhead production per well, with an average CGR of 271 Bbl/MMcf.(1)
- Six new Montney wells on the 3-10 pad at Karr were brought onstream in February 2021, two months ahead of schedule. The wells averaged 1,850 Boe/d (5.1 MMcf/d of shale gas and 1,000 Bbl/d of NGLs) of raw wellhead production per well over the first 20 days of production with an average CGR of 196 Bbl/MMcf.(1)
- At Wapiti, five Montney wells on the 5-3 West pad were brought onstream in 2020 and averaged 1,271 Boe/d (2.7 MMcf/d of shale gas and 827 Bbl/d of NGLs) of peak 30-day wellhead production per well, with an average CGR of 311 Bbl/MMcf.(2) A pre-existing tenure well was also brought onstream.
- Through a continued focus on innovation, technological advancement and efficient execution, the Company realized significant cost savings in its 2020 capital program without compromising deliverability from new wells. Cost savings have been achieved across many aspects of the capital program through improvements in well design, drill bit technology, fluid selection and reducing vendor rates.
  - All-in lease construction, drilling, completion, equip and tie-in (collectively, "DCET") costs for the five-well Karr 5-16 West pad averaged $7.5 million per well.

(1) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 7% and liquids sales volumes are lower by approximately 7% due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. CGRs are calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See Oil and Gas Measures and Definitions in the Advisories section.

(2) Production measured at the wellhead. Natural gas sales volumes are lower by approximately 15% and liquids sales volumes are lower by approximately 3% due to shrinkage. Excludes days when the wells did not produce. The production rates and volumes stated are over a short period of time and, therefore, are not necessarily indicative of average daily production, long-term performance or of ultimate recovery from the wells. CGRs are calculated by dividing raw wellhead liquids volumes by raw wellhead natural gas volumes. See Oil and Gas Measures and Definitions in the Advisories section.

- Drilling of the six-well Karr 3-10 pad finished ahead of schedule allowing the Company to accelerate completion operations into 2020. Preliminary DCET costs averaged a pacesetting $7.0 million per well.

- DCET costs for the last four pads (comprised of 21 wells) at Karr averaged approximately $7.5 million per well. As a consequence of structural cost improvements, the Company is revising downward its internal Karr type well DCET cost assumption to $7.5 million from the previous assumption of $8.4 million, the latter of which was used by the Company's independent third-party reserves evaluator in the preparation of the 2020 reserves report.(1)

- At Wapiti, DCET costs on the five-well 5-3 West pad averaged $7.6 million per well. This represents a 27% reduction compared with average DCET costs for the initial two Wapiti pads and is consistent with Paramount's internal type well DCET cost assumption for Wapiti of $7.9 million, which was also used by the Company's independent third-party reserves evaluator in the preparation of the 2020 reserves report. (1)

2021 GUIDANCE

The Company's capital budget for 2021 is expected to range between $230 million and $260 million, excluding land acquisitions and abandonment and reclamation activities. Over 60% of the capital budget will be incurred in the first half of 2021. Approximately 85% of the 2021 program will be focused on advancing the Company's liquids-rich Montney developments at Karr and Wapiti. Approximately 70% of the 2021 capital budget is being allocated to sustaining capital and maintenance activities and the remaining 30% to production growth.

- At Karr, Paramount plans to drill 21 Montney wells and bring onstream a total of 19 wells in 2021. The six-well 3-10 pad was brought on production in February 2021, and the Company is currently drilling the three-well 4-28 East pad and the five-well 7-18 Pad that are expected to be onstream late in the second quarter and third quarter, respectively. The Company also plans to drill and bring onstream the five-well 5-16 East pad by the end of the third quarter and begin drilling the ten-well 16-17 pad during the fourth quarter.

- At Wapiti, the Company is currently drilling the remaining four Montney wells on the seven-well 6-4 pad. All seven wells are expected to be brought onstream starting in the third quarter of 2021. The Company also plans to drill a tenure well at Wapiti in 2021.

- Other key activities include a two-well Duvernay pad at Willesden Green, completion of a single well at Ante Creek (Montney oil) and the initiation of an enhanced oil recovery pilot at the Kaybob North Montney oil pool.

The Company expects 2021 sales volumes to average between 77,000 Boe/d and 80,000 Boe/d (45% liquids), slightly higher than preliminary guidance after accounting for first quarter dispositions of approximately 2,600 Boe/d of annualized production. (2)

- First half 2021 sales volumes are expected to average between 74,000 Boe/d and 76,000 Boe/d (43% liquids) as the majority of new wells will be brought on later in the year and volumes will be impacted by a scheduled outage at Karr in the second quarter.

- Despite a scheduled outage at Wapiti in the third quarter, second half 2021 sales volumes are expected to increase to average between 80,000 Boe/d and 84,000 Boe/d (46% liquids) as additional liquids-rich wells are brought onstream.

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(1) Readers are referred to the advisories concerning "Reserves Data" in the Advisories section of this document.
(2) See the Product Type Information section for further information respecting the composition of forecast sales volumes.

The Company forecasts 2021 free cash flow of approximately $160 million based on: (i) the midpoint of forecast capital spending and production, (ii) $25 million in abandonment and reclamation costs, (iii) realized pricing of $39.50/Boe (US$58.60/Bbl WTI, US$3.00/MMBtu NYMEX, $2.80/GJ AECO), (iv) operating costs of $11.65/Boe, and (v) transportation and processing costs of $4.00/Boe. With approximately 57% of forecast midpoint 2021 production hedged, forecast free cash flow would still be approximately $100 million at an average 2021 WTI oil price of US$43.50/Bbl.[(1)]

The Company has budgeted approximately $31 million for abandonment and reclamation activities in 2021. Approximately $6 million is to be funded directly through the Alberta Site Rehabilitation Program ("ASRP"), resulting in approximately $25 million net to Paramount. The majority of these funds will be directed to the Zama area.

(1) "Free cash flow" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

RESERVES [1]

- Despite a significant reduction in commodity price assumptions used by the independent third-party reserves evaluator, Paramount's 2020 proved plus probable ("P+P") reserves were unchanged versus 2019 at 632 MMBoe while proved developed producing ("PDP") reserves increased by 8% to 121 MMBoe. This reflects the Company's success in sustainably reducing both its operating and capital cost structure, as well as improvements in well performance. Optimizing Paramount's 5-year capital program resulted in a 2020 total proved ("TP") reserves decrease of 7% to 311 MMBoe compared to 335 MMBoe in 2019.

- Total undiscounted future development costs were reduced by $962 million for TP reserves and by $1,196 million for P+P reserves. Further reductions may be realized if actual DCET costs continue to be lower than the costs used by the Company's independent third-party reserves evaluator in 2020.

- The liquids weighting of the Company's 2020 reserves remain largely unchanged from 2019 (P+P 53% natural gas, 39% condensate and oil, 8% other NGLs).

- The Company's reserves replacement ratio was 1.4x for PDP reserves.

- PDP finding and development costs were $6.31/Boe in 2020.

- Estimated future net revenue at December 31, 2020, discounted at 10% before tax, totaled $1.9 billion for TP reserves and $3.6 billion for P+P reserves.

ENVIRONMENTAL, SOCIAL AND GOVERNANCE

Paramount has a long history of sustainable resource development and environmental stewardship and is committed to creating value for our stakeholders in an environmentally and socially responsible manner. Environmental, Social and Governance ("ESG") highlights in 2020 include:

- Publication of the Company's inaugural ESG report, which is available on Paramount's website at http://www.paramountres.com.

- Participation in the 2020 CDP Climate Change Survey.

- Completion of a multi-year project to replace approximately 1,900 high vent controllers with modern low or no vent units, reducing Paramount's annual greenhouse gas emissions by an estimated 75,000 tonnes of carbon dioxide equivalent ("tCO_2e"). Information about Paramount's other emissions reduction activities can be found in our ESG report.

- Paramount has implemented a corporate pandemic response plan aimed at ensuring the health and safety of its staff and contractors and the people they come in contact with. The Company is conducting its operations in compliance with public health requirements and guidelines, including providing additional personal protective equipment and restricting access to its work sites to critical personnel.

(1) Readers are referred to the advisories concerning "Reserves Data" and "Oil and Gas Measures and Definitions" in the Advisories section of this document. Reserves evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel") as of December 31, 2020 and December 31, 2019 in accordance with National Instrument 51-101 definitions, standards and procedures. Reserves are gross reserves representing working interest before royalties. Net present values of future net revenue were determined using forecast prices and costs and do not represent fair market value.

CORPORATE

- To provide greater certainty of free cash flow levels and the funding of the Company's 2021 capital program, Paramount has hedged approximately 57% of its 2021 forecast production. The Company's current 2021 hedging position is summarized below:

  - Natural Gas: approximately 67,400 MMBtu/d at US$2.73/MMBtu and approximately 89,200 GJ/d at CDN$2.53/GJ over 2021.

  - Oil: approximately 18,100 Bbl/d at US$46.35/Bbl in 2021 and 3,000 Bbl/d at CDN$65.29/Bbl in the second and third quarters.

  - Condensate: 1,000 Bbl/d at US$WTI plus US$0.50/Bbl in the first quarter and 4,000 Bbl/d at US$WTI plus US$0.06/Bbl in the second quarter.

- Paramount's natural gas diversification strategy includes arrangements to sell approximately 60,000 GJ/d of natural gas at Dawn, approximately 22,000 GJ/d of natural gas at Malin, and 40,000 GJ/d of natural gas sales priced in the US Midwest.

- The Company's long-term debt at December 31, 2020 was $813 million. In January 2021, Paramount's $1.0 billion senior secured revolving bank credit facility was amended to remove prior conditions on facility availability in excess of $900 million. Concurrent with the amendments, the Company completed a private placement of $35 million of senior unsecured convertible debentures.

- In March 2021, the Company elected to exit the covenant relief period under its $1.0 billion bank credit facility prior to the scheduled expiry of the period on June 30, 2021.

Product Type Information

This document refers to sales volumes of "liquids", "natural gas", "condensate and oil" and "other NGLs". "Liquids" means NGLs (including condensate) and oil combined, "natural gas" refers to conventional natural gas and shale gas combined, "condensate and oil" refers to condensate, light and medium crude oil and tight oil combined and "other NGLs" refers to ethane, propane and butane. See the Product Type Information section at page 107 of this document for a complete breakdown of sales volumes for applicable periods by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

Advisories

Readers are referred to the Advisories section at page 109 of this document for important information and advisories respecting Forward-looking Information, Non-GAAP financial measures, Reserves Data and Oil and Gas Measures and Definitions.

FINANCIAL AND OPERATING RESULTS [(1)]

($ millions, except as noted)

	Three months ended December 31				Twelve months ended December 31			
	2020		2019		2020		2019	
Net income (loss)	311.5		(31.1)		(22.7)		(87.9)	
per share – basic and diluted ($/share)	*2.35*		*(0.24)*		*(0.17)*		*(0.67)*	
Cash from operating activities	53.2		70.5		80.9		255.7	
per share – basic and diluted ($/share)	*0.40*		*0.54*		*0.61*		*1.96*	
Adjusted funds flow	67.9		93.5		150.0		299.0	
per share – basic and diluted ($/share)	*0.51*		*0.71*		*1.12*		*2.29*	
Total assets					3,497.0		3,531.3	
Long-term debt					813.5		632.3	
Net debt					854.1		703.5	
Common shares outstanding *(thousands)* (2)					132,284		133,337	
Sales volumes								
Natural gas (MMcf/d)	256.3		299.0		248.7		303.3	
Condensate and oil (Bbl/d)	25,752		28,516		22,565		25,079	
Other NGLs (Bbl/d) (3)	4,987		7,064		4,325		6,767	
Total (Boe/d)	73,460		85,411		68,340		82,394	
% liquids	*42%*		*42%*		*39%*		*39%*	
Grande Prairie Region (Boe/d)	37,782		36,789		31,076		29,040	
Kaybob Region (Boe/d)	27,056		33,167		28,685		35,500	
Central Alberta and Other Region (Boe/d)	8,622		15,455		8,579		17,854	
Total (Boe/d)	73,460		85,411		68,340		82,394	
Netback		*$/Boe (4)*		*$/Boe (4)*		*$/Boe (4)*		*$/Boe (4)*
Natural gas revenue	66.7	*2.83*	75.1	*2.73*	204.9	*2.25*	261.0	*2.36*
Condensate and oil revenue	123.3	*52.03*	175.0	*66.70*	383.8	*46.47*	610.2	*66.66*
Other NGLs revenue (3)	9.5	*20.61*	8.5	*13.03*	24.7	*15.63*	37.7	*15.24*
Royalty and other revenue	2.5	—	1.3	—	12.6	—	6.0	—
Petroleum and natural gas sales	202.0	*29.89*	259.9	*33.08*	626.0	*25.03*	914.9	*30.42*
Royalties	(11.7)	*(1.73)*	(17.2)	*(2.19)*	(31.3)	*(1.25)*	(63.3)	*(2.10)*
Operating expense	(79.8)	*(11.80)*	(105.0)	*(13.36)*	(297.1)	*(11.88)*	(376.0)	*(12.50)*
Transportation and NGLs processing (5)	(24.6)	*(3.63)*	(22.8)	*(2.90)*	(101.3)	*(4.05)*	(94.7)	*(3.15)*
Netback	85.9	*12.73*	114.9	*14.63*	196.3	*7.85*	380.9	*12.67*
Commodity contract settlements	7.9	*1.18*	4.7	*0.60*	37.6	*1.50*	13.2	*0.44*
Netback including commodity contract settlements	93.8	*13.91*	119.6	*15.23*	233.9	*9.35*	394.1	*13.11*
Total capital expenditures								
Grande Prairie Region (6)	64.3		60.7		196.9		302.2	
Kaybob Region	1.8		9.5		16.4		80.7	
Central Alberta and Other Region	0.8		0.6		4.6		7.6	
Corporate (7)	(1.8)		—		2.3		6.0	
Land and property acquisitions	—		1.4		0.6		7.6	
Total	65.1		72.2		220.8		404.1	
Asset retirement obligations settlements	0.1		18.0		35.0		29.4	

(1) Readers are referred to the advisories concerning Non-GAAP Measures and Oil and Gas Measures and Definitions in the Advisories section of this document. This table contains the following Non-GAAP measures: Adjusted funds flow, Net debt, Netback and Total capital expenditures. Readers are referred to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by specific product type.
(2) Common shares are presented net of shares held in trust under the Company's restricted share unit plan (000's of common shares): 2020: 1,914; 2019: 860; 2018: 574.
(3) Other NGLs means ethane, propane and butane.
(4) Natural gas revenue presented as $/Mcf.
(5) Includes downstream transportation costs and NGLs fractionation costs.
(6) Total capital expenditures for the year ended December 31, 2019 includes $45.5 million of capital spending related to the Karr 6-18 natural gas facility prior to its sale (three months ended December 31, 2019 – nil).
(7) Corporate capital expenditures includes transfers between regions.

REVIEW OF OPERATIONS

2020 was defined by the challenges arising from the impact of the COVID-19 pandemic and the Company's successful response. Paramount responded swiftly to the material deterioration in prices arising in connection with both the disputes among members of OPEC+ in late-February and the COVID-19 pandemic by adjusting its capital plans and implementing aggressive cost reduction initiatives. As a result of these actions, Paramount exited 2020 with a significantly lower cost structure and is positioned to deliver free cash flow for both production growth and debt reduction.

Paramount's 2020 achievements include:

- Reducing average DCET costs by 36% at Karr compared to 2018-2019 and by 27% at Wapiti compared to the initial two Wapiti pads, resulting in significantly improved capital efficiencies, without compromising completion effectiveness.
- Bringing on production 21 new Montney wells in the Grande Prairie Region, including 10 in the fourth quarter.
- Exceeding the previously announced targets for operating cost and G&A reductions of $25 million and $15 million, respectively.
- Completing the Company's multi-year project to replace all high vent controllers with low or no vent units, reducing GHG emissions by an estimated 75,000 tCO_2e per year.
- Abandoning 254 wells and completing the permanent suspension of all pipelines and facilities at Zama under the Company's area-based closure program.

Company sales volumes averaged 68,340 Boe/d (39% liquids) in 2020 and 73,460 Boe/d (42% liquids) in the fourth quarter of 2020. Volumes in the second half of 2020 increased as the Company brought onstream 21 liquids rich Montney wells at Karr and Wapiti. Production from the Grande Prairie Region in the fourth quarter of 2020 comprised 51% of Company sales volumes, averaging 37,782 Boe/d (58% liquids).

The Company's capital allocation remains focused on its two large-scale Montney developments at Karr and Wapiti in the Grande Prairie Region. Paramount expects to materially grow production in the Grande Prairie Region in 2021. The Company also anticipates directing modest capital spending to certain Montney oil and Duvernay projects in the Kaybob and Central and Other Regions to advance those plays and to retain land.

Paramount continues to focus on enhancing netbacks by improving reliability across its portfolio, optimizing field operations and lowering operating costs, while continuing to prioritize safety and operational integrity. The Company's 2021 hedging program, combined with its gas market diversification strategy, provides greater certainty of both 2021 free cash flow levels and the funding of its capital program.

The Company's capital budget for 2021 is expected to range between $230 million and $260 million, excluding land acquisitions and abandonment and reclamation activities. Over 60% of the capital budget will be incurred in the first half of 2021. Approximately 85% of the 2021 program will be focused on advancing the Company's liquids-rich Montney developments at Karr and Wapiti. Approximately 70% of the 2021 capital budget is being allocated to sustaining capital and maintenance activities and the remaining 30% to production growth.

Paramount expects 2021 sales volumes to average between 77,000 Boe/d and 80,000 Boe/d (45% liquids), slightly higher than preliminary guidance after accounting for first quarter dispositions of approximately of 2,600 Boe/d (15 MMcf/d of conventional natural gas and 135 Bbl/d of NGLs) of expected 2021 annualized production. Sales volumes are anticipated to average between 74,000 Boe/d and 76,000 Boe/d (43% liquids) in the first half of 2021 as the majority of new wells are scheduled to be brought onstream in the second half of the year. A scheduled outage at Karr in the second quarter will also impact first half production. Despite a scheduled outage at Wapiti in the third quarter, second half 2021 sales volumes are expected to increase to average between 80,000 Boe/d and 84,000 Boe/d (46% liquids) as more liquids-rich wells are brought onstream.

The Company has budgeted approximately $31 million for abandonment and reclamation activities in 2021. Approximately $6 million is to be funded directly through government programs resulting in approximately $25 million of net costs to Paramount. To date, the Company has received approval for up to approximately $14 million of funding under the ASRP of which approximately $10 million remains available for use in 2021 and 2022, inclusive of the expected approximate $6 million to be used in 2021. Paramount anticipates abandoning approximately 170 wells in 2021 with the majority of activities to be focused in the Zama area.

GRANDE PRAIRIE REGION

Development activities in the Grande Prairie Region are focused at the Karr and Wapiti properties, located south of Grande Prairie, Alberta, in the over-pressured liquids-rich Deep Basin Montney trend. There are three potential development layers in the Montney formation at Karr and Wapiti, two of which are currently being developed. At December 31, 2020, Paramount held approximately 98,000 net acres of Montney rights in the Grande Prairie Region.

Grande Prairie Region sales volumes averaged 31,076 Boe/d in 2020, the majority of which was liquids-rich production from the Karr development. Capital investment in 2020 in the Grande Prairie Region totaled approximately $197 million, which was focused primarily on drilling and completion operations at both Karr and Wapiti.

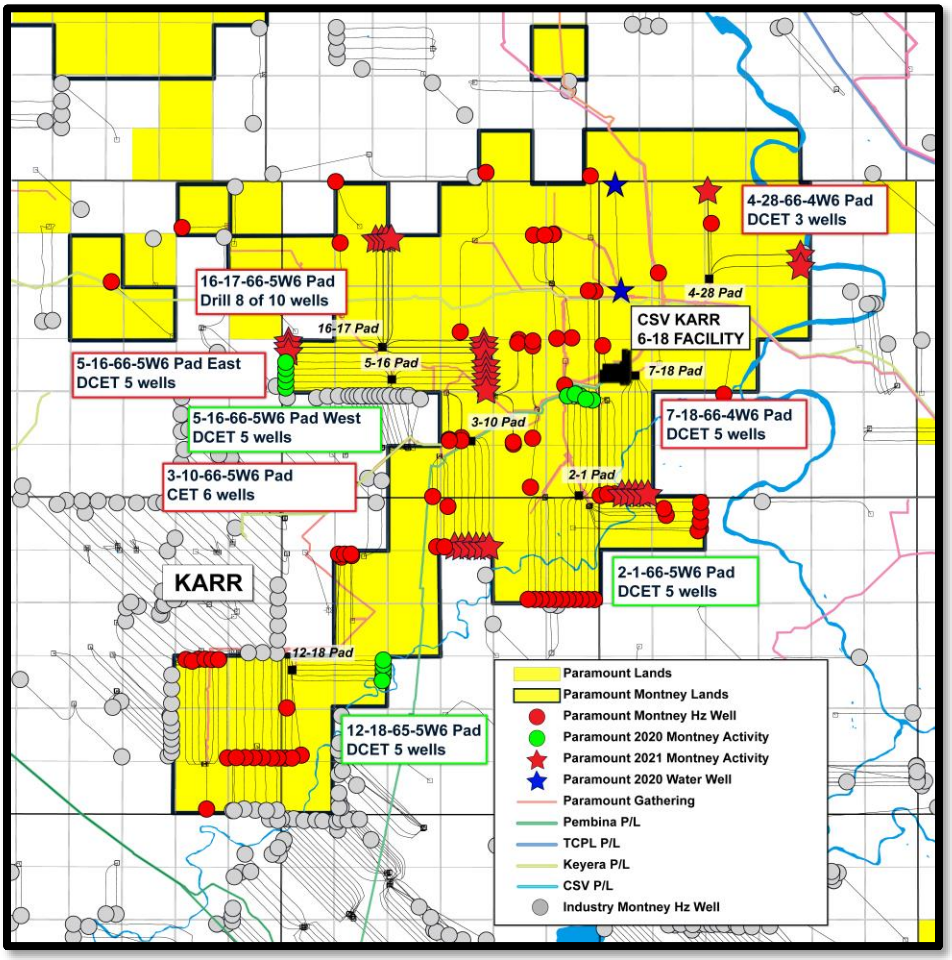
Grande Prairie Region sales volumes and netbacks are summarized below:

	Three Months ended December 31				Twelve Months ended December 31			
	2020		2019		**2020**		2019	
Sales volumes (1)								
Natural gas (MMcf/d)	**94.3**		93.4		**78.6**		79.5	
Condensate and oil (Bbl/d)	**19,635**		18,851		**16,005**		13,973	
Other NGLs (Bbl/d)	**2,429**		2,376		**1,964**		1,814	
Total (Boe/d)	**37,782**		36,789		**31,076**		29,040	
% liquids	***58%***		*58%*		***58%***		*54%*	
Netback	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)	($ millions)	($/Boe)
Petroleum and natural gas sales	**125.1**	***36.00***	142.9	*42.21*	**356.2**	***31.32***	423.3	*39.94*
Royalties	**(6.2)**	***(1.78)***	(9.6)	*(2.82)*	**(14.3)**	***(1.26)***	(35.1)	*(3.32)*
Operating expense	**(42.4)**	***(12.20)***	(48.1)	*(14.20)*	**(162.4)**	***(14.28)***	(141.7)	*(13.37)*
Transportation (2)	**(14.2)**	***(4.07)***	(11.0)	*(3.24)*	**(53.1)**	***(4.66)***	(33.5)	*(3.16)*
	62.3	***17.95***	74.2	*21.95*	**126.4**	***11.12***	213.0	*20.09*

(1) Readers are referred to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by specific product type.

(2) Transportation costs includes NGLs processing

KARR AREA



Cash flows at Karr benefit from a liquids-rich product mix. Karr sales volumes and netbacks are summarized below:

	Three Months ended December 31				Twelve Months ended December 31			
	2020		2019		**2020**		2019	
Sales volumes (1)								
Natural gas (MMcf/d)	**70.5**		69.1		**56.3**		67.7	
Condensate and oil (Bbl/d)	**13,348**		11,816		**10,028**		10,024	
Other NGLs (Bbl/d)	**1,817**		1,614		**1,361**		1,453	
Total (Boe/d)	**26,914**		24,943		**20,777**		22,755	
% liquids	***56%***		*54%*		***55%***		*50%*	
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Petroleum and natural gas sales	**86.1**	***34.79***	92.5	*40.32*	**234.6**	***30.86***	316.8	*38.14*
Royalties	**(4.6)**	***(1.87)***	(6.9)	*(2.99)*	**(9.7)**	***(1.28)***	(29.7)	*(3.58)*
Operating expense	**(27.8)**	***(11.24)***	(30.5)	*(13.29)*	**(107.2)**	***(14.10)***	(99.8)	*(12.01)*
Transportation (2)	**(10.5)**	***(4.26)***	(6.9)	*(3.00)*	**(35.4)**	***(4.65)***	(26.1)	*(3.14)*
	43.2	***17.42***	48.2	*21.04*	**82.3**	***10.83***	161.2	*19.41*

(1) Readers are referred to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by specific product type.

(2) Transportation costs includes NGLs processing

The 2020 capital program at Karr focused on completing and bringing on production five wells on the 2-1 pad that were drilled in 2019 and the drilling, completing and bringing on production of five wells on the 12-18 pad, one of which was drilled in 2019, and five wells on the 5-16 West pad. The Company also drilled and commenced completion operations on the six-well 3-10 pad and commenced lease construction and drilling of the five-well 7-18 pad. In addition, Paramount completed a debottlenecking project to alleviate gathering system constraints in the southwest area of Karr and brought into service two water disposal wells. These water disposal wells have materially reduced operating costs associated with flowback water as third-party disposal and trucking fees are largely eliminated.

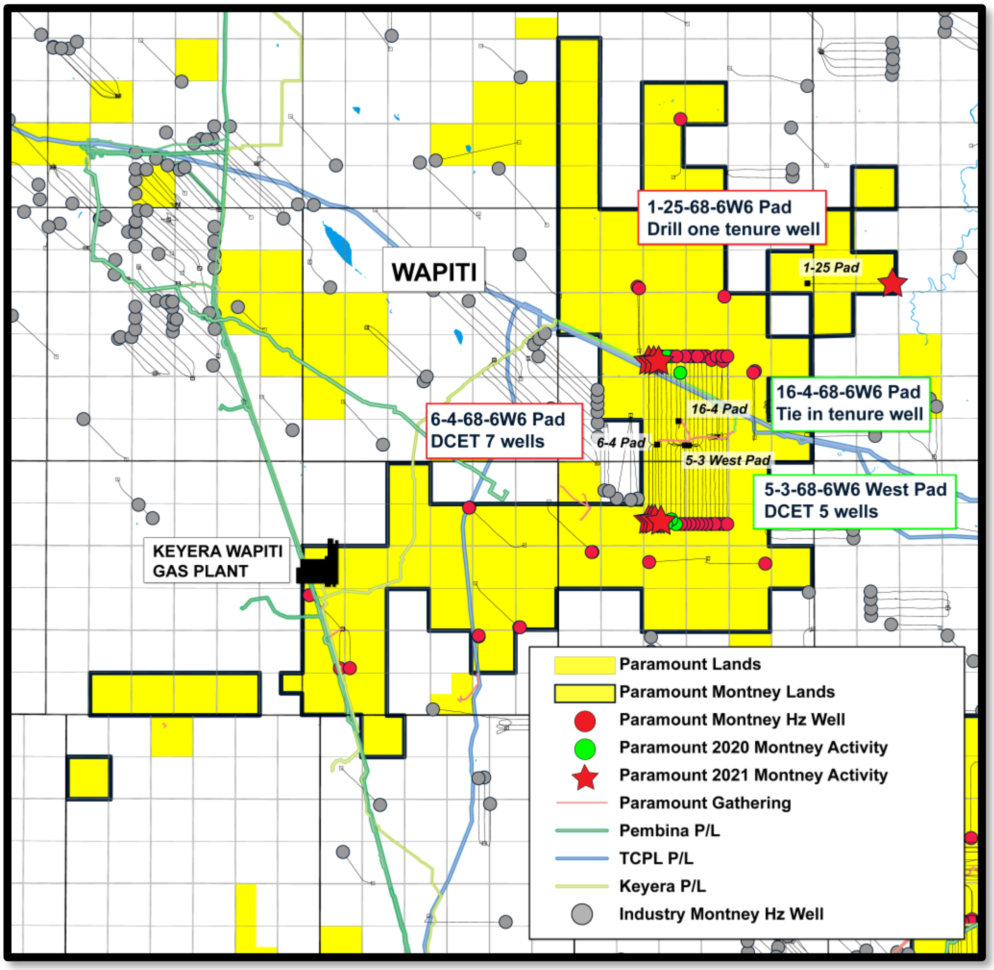
The Company's focus on continuous improvement coupled with lower vendor rates in 2020 has resulted in significantly stronger capital efficiencies with average DCET costs that were 36% lower in 2020 than average costs over 2018 and 2019. In 2020, Paramount implemented data analytics workflows that have enabled the generation of advanced predictive models to rapidly assess development opportunities at its Grande Prairie Montney assets under a variety of scenarios and implement changes to completion design, well spacing and other factors to maximize risk-adjusted returns. Optimized well and completion design, new drill bit technology, lower vendor rates and higher efficiencies all contributed to the significant DCET cost improvements in 2020.

2020 sales volumes at Karr were approximately 9% lower compared to 2019 due to a combination of natural declines, as fifteen new Montney wells were not brought onstream until the second half of 2020, and high pressure backout in the gathering system prior to the completion of the debottlenecking project in the third quarter of 2020. Fourth quarter sales volumes increased approximately 40% to 26,914 Boe/d (56% liquids) compared to 19,246 Boe/d (57% liquids) in the third quarter.

Lower commodity prices and higher transportation and operating costs resulted in lower Karr netbacks in 2020 compared to 2019. Transportation and operating costs were higher in 2020 as a result of additional capacity associated with the completion of the third-party Karr 6-18 expansion in the third quarter. Per unit operating costs at Karr are forecast to decrease as volumes continue to increase. Fourth quarter 2020 operating costs were $11.24/Boe compared to $14.10/Boe for the full year, benefitting from new well production that came onstream in the third and fourth quarters.

Activities at Karr in 2021 will focus on drilling and completion operations. The Company plans to drill 21 Montney wells and bring onstream a total of 19 Montney wells. The six-well 3-10 pad was brought on production in February, two months ahead of schedule, and the Company is currently drilling the three-well 4-28 East pad and the five-well 7-18 pad that are expected to be brought onstream in the second quarter and third quarter, respectively. The Company also plans to drill and bring on production the five-well 5-16 East pad by the end of the third quarter and commence the drilling of the ten-well 16-17 pad in the fourth quarter, with eight of these wells anticipated to be drilled by year end.

WAPITI AREA



Wapiti sales volumes and netbacks are summarized below:

	Three Months ended December 31				Twelve Months ended December 31			
	2020		2019		**2020**		2019	
Sales volumes (1)								
Natural gas (MMcf/d)	**23.3**		23.6		**21.9**		11.1	
Condensate and oil (Bbl/d)	**6,286**		6,865		**5,959**		3,879	
Other NGLs (Bbl/d)	**589**		706		**591**		344	
Total (Boe/d)	**10,764**		11,498		**10,207**		6,082	
% liquids	***64%***		*66%*		***64%***		*69%*	
Netback	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*	($ millions)	*($/Boe)*
Petroleum and natural gas sales	**38.9**	***39.30***	49.2	*46.49*	**121.0**	***32.39***	103.1	*46.43*
Royalties	**(1.6)**	***(1.58)***	(2.5)	*(2.37)*	**(4.6)**	***(1.23)***	(5.6)	*(2.51)*
Operating expense	**(14.2)**	***(14.36)***	(16.2)	*(15.29)*	**(53.6)**	***(14.35)***	(38.7)	*(17.44)*
Transportation (2)	**(3.6)**	***(3.62)***	(4.4)	*(4.14)*	**(17.6)**	***(4.71)***	(8.5)	*(3.82)*
	19.5	***19.74***	26.1	*24.69*	**45.2**	***12.10***	50.3	*22.66*

(1) Readers are referred to the Product Type Information section of this document for a complete breakdown of sales volumes for applicable periods by specific product type.

(2) Transportation costs includes NGLs processing

Activities in 2020 at Wapiti focused on drilling, completing and bringing on production the five-well 5-3 West pad and drilling three wells on the seven-well 6-4 pad. Similar to Karr, Wapiti benefited from significant cost efficiencies in 2020. All-in DCET costs averaged $7.6 million per well, approximately 21% lower than average costs at the twelve-well 5-3 East pad drilled in 2019 and approximately 32% lower than average costs at the eleven-well 9-3 pad drilled in 2018. A tenure well that was drilled and completed in 2015 was tied-in and brought on production in the third quarter. Additional emulsion gathering system capacity was put into service by the third-party operator of the Wapiti natural gas processing plant (the "Wapiti Plant") in 2020 which allowed the Company to bring additional liquids-rich wells onstream.

Production in 2020 was impacted by four outages at the Wapiti Plant that totaled approximately 10 weeks of outage time over the course of the year. This impacted the Company's 2020 sales volumes by an estimated 2,200 Boe/d. Paramount is pursuing a claim under its contingent business interruption insurance policy in respect of a third quarter outage at the Wapiti Plant.

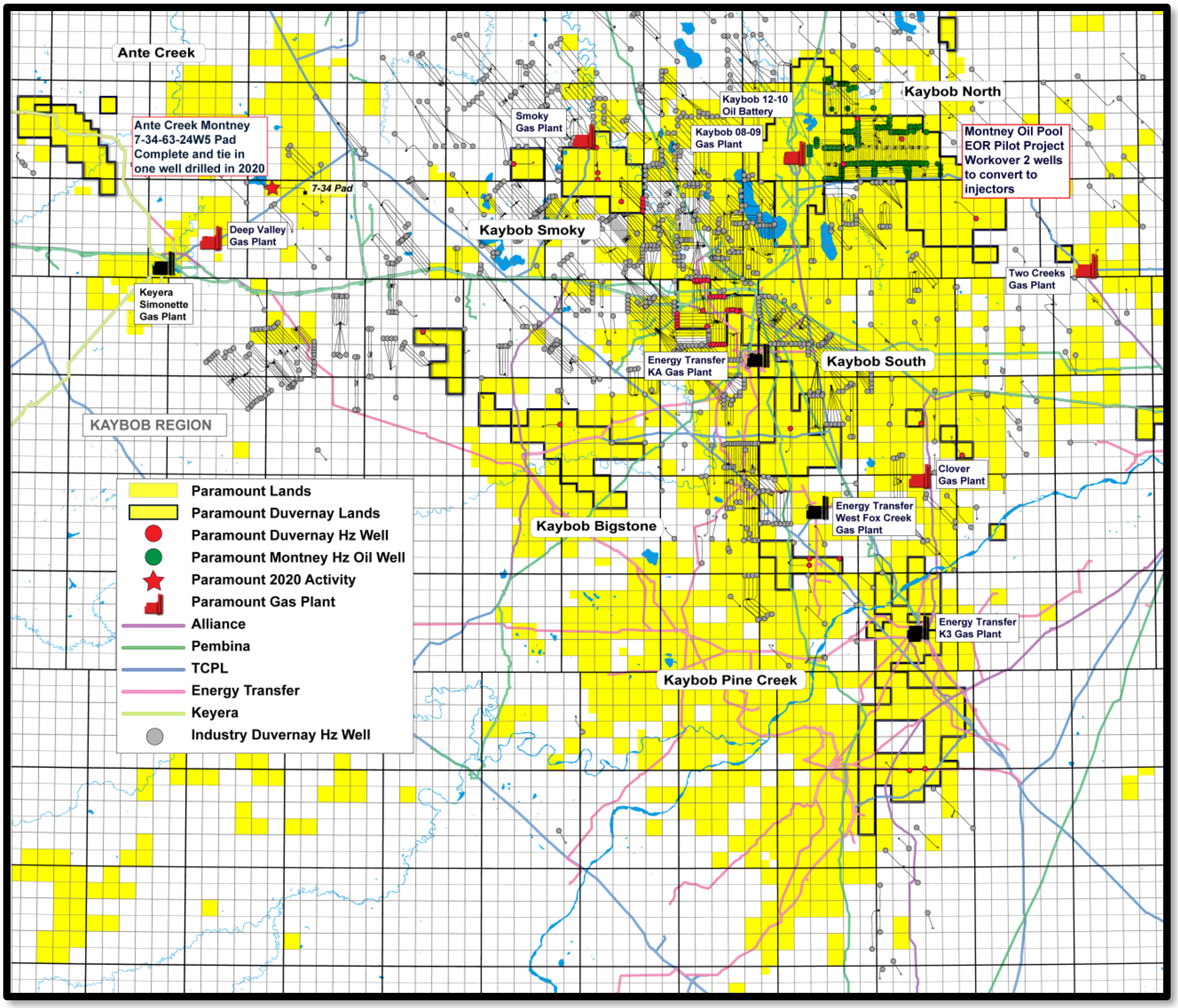
Increased sales volumes in 2020 compared to 2019 are attributable to a full year of production as Paramount's Wapiti development commenced operations in May 2019 following start-up of the Wapiti Plant. Per unit netbacks were lower in 2020 than 2019 primarily as a result of lower commodity prices.

In 2021, Paramount plans to complete the drilling of the remaining four wells on the seven-well 6-4 pad and complete, tie-in and bring on production all seven wells starting in the third quarter of 2021. Wapiti volumes will be impacted by a scheduled outage in the third quarter. The Company also plans to drill a land tenure well in 2021.

KAYBOB REGION

Paramount has a large portfolio of resource plays in the Kaybob Region, including approximately 200,000 net acres of Duvernay rights and approximately 272,000 net acres of Montney rights.

The Company's key development areas include Montney formation targets at Kaybob North and Ante Creek and Duvernay formation targets at Kaybob Smoky, Kaybob South and Kaybob North.



Kaybob Region sales volumes averaged 28,685 Boe/d (27% liquids) in 2020. Capital spending totaled approximately $16.4 million. Activities in 2020 were focused on land retention, with the drilling of one well at Ante Creek. In 2021 the Company plans to complete, tie-in and bring on production this well as well as initiate an enhanced oil recovery pilot project on a portion of the Kaybob North Montney oil development to assess the viability of implementing the program across the entire field. A total of two wells will be converted from producing to water injection wells as part of this pilot project.

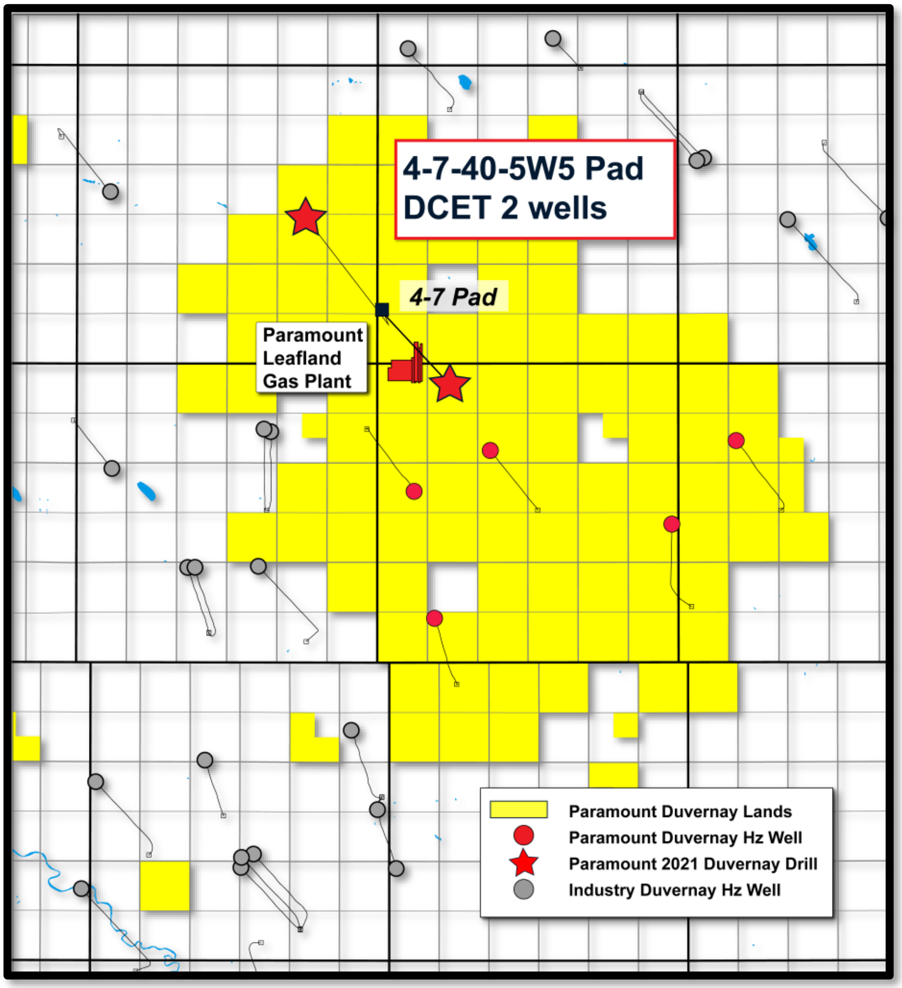
Material cost savings were achieved in 2020 in the Kaybob Region after an extensive review of operations and ensuing optimization projects. Operating costs per Boe were reduced by 11 percent in 2020 in the Kaybob Region, from $11.71/Boe in 2019 to $10.39/Boe in 2020. The Company continues to seek further efficiencies while seeking to maintain best practices in safety, asset integrity, reliability and environmental performance.

Strong results from competitor activity continue to de-risk the Kaybob Region's land base. Paramount uses this competitor data, along with its proprietary information, to evaluate full field development plans for these areas. Recent transactions in the areas surrounding the Company's Kaybob North Duvernay asset, including indications by the purchasers of their intent to increase investment and activity on the acquired assets, will continue to de-risk Paramount's lands.

Paramount owns and operates extensive gathering and processing infrastructure in the Kaybob Region that supports current production, drives down operating costs and generates third party processing income. This infrastructure can support production growth in the medium term as capital is directed to the area. The Company's crude oil terminal that was put into service late in 2019 provides the Company with the opportunity to increase netbacks for its Kaybob area crude oil and condensate volumes and to capture incremental value in price differentials.

CENTRAL ALBERTA AND OTHER REGION

The Central Alberta and Other Region includes multiple land and resource plays, including approximately 71,000 net acres of Duvernay rights at Willesden Green and 21,000 net acres of Montney rights at Birch in British Columbia. The Region also includes lands and production in the Horn River play in northeast British Columbia. The map below highlights the Company's land position at Willesden Green.



Central Alberta and Other Region sales volumes averaged 8,579 Boe/d (14% liquids) in 2020. In late 2019, Paramount sold properties in the Region for cash proceeds of approximately $55 million with average annual production of approximately 8,500 Boe/d (30.6 MMcf/d of conventional natural gas, 2,947 Bbl/d of NGLs and 466 Bbl/d of light and medium crude oil). Capital spending in 2020 totaled $4.6 million, the majority of which was related to the completion of one (0.5 net) well at Birch in British Columbia and maintenance activities.

In 2021, the Company plans to drill, complete, tie-in and bring on production two new liquids-rich Duvernay wells in the Willesden Green area and drill, complete and bring on production one exploration well in southern Alberta.

GREENHOUSE GAS REDUCTION INITIATVE

As part of Paramount's continued commitment to responsible energy development, the Company has been participating in greenhouse gas ("GHG") emission reduction programs and investing in new equipment to reduce GHG emissions from its operations. In 2020 Paramount completed its multi-year project to replace approximately 1,900 high vent controllers with modern low or no vent units. It is estimated that this project will reduce annual GHG emissions by approximately 75,000 tCO_2e compared to baseline 2017 emissions. Paramount continues to evaluate its assets for further emission reduction opportunities.

RESERVES AND FINDING AND DEVELOPMENT COSTS [(1)]

Despite a significant reduction in commodity price assumptions used by the third-party reserve evaluator, Paramount's 2020 P+P reserves were unchanged versus 2019 at 632 MMBoe while PDP reserves increased by 8% to 121 MMBoe, reflecting the Company's success in sustainably reducing both its operating and capital cost structure, as well as improvements in well performance. Optimizing Paramount's 5-year capital program resulted in a 2020 TP reserves decrease of 7% to 311 MMBoe compared to 335 MMBoe in 2019. The liquids weighting of the Company's 2020 reserves remain largely unchanged from 2019 (P+P 53% natural gas, 39% condensate and oil, 8% other NGLs).

Total undiscounted future development costs were reduced by $962 million for TP reserves and by $1,196 million for P+P reserves. Further reductions may be realized if actual DCET costs continue to be lower than the costs used by the Company's independent third-party reserves evaluator in 2020.

The Company's reserves replacement ratio was 1.4x for PDP reserves and PDP finding and development costs were $6.31/Boe in 2020.

Estimated future net revenue at December 31, 2020, discounted at 10% before tax, totaled $1.9 billion for TP reserves and $3.6 billion for P+P reserves.

Reserves by Product

Total Company gross reserves at December 31, 2020 and 2019 were as follows:

	Proved			Proved plus Probable		
	2020	2019	*% Change*	**2020**	2019	*% Change*
Natural gas (Bcf)	**1,014.4**	1,059.5	*(4)*	**1,994.3**	1,993.8	—
NGLs (MBbl)	**126,080**	141,238	*(11)*	**258,217**	264,917	*(3)*
Crude oil (MBbl)	**16,176**	16,997	*(5)*	**41,431**	34,875	*19*
Total (MBoe)	**311,317**	334,817	*(7)*	**632,025**	632,097	—

(1) Readers are referred to the advisories concerning Reserves Data and Oil and Gas Measures and Definitions in the Advisories section of this document. Reserves evaluated by McDaniel and Associates Consultants Ltd. ("McDaniel") as of December 31, 2020 and December 31, 2019 in accordance with National Instrument 51-101 definitions, standards and procedures. Working interest reserves before royalty deductions. Net present values of future net revenue were determined using forecast prices and costs and do not represent fair market value.

Reserves by Category

The following table summarizes the Company's gross proved and proved plus probable developed reserves and undeveloped reserves as at December 31, 2020 and the net present value of future net revenue of such reserves before income taxes, undiscounted and discounted at 10%.

	Proved (1)			**Proved plus Probable** (1)		
	Gross Reserves	**Future Net Revenue NPV Before Tax** ($ millions)		**Gross Reserves**	**Future Net Revenue NPV Before Tax** ($ millions)	
	(MBoe)	0%	10%	(MBoe)	0%	10%
Developed	120,659	219	897	158,952	773	1,172
Undeveloped	190,658	2,147	978	473,073	6,456	2,477
Total	**311,317**	**2,366**	**1,875**	**632,025**	**7,229**	**3,649**

(1) Columns and rows may not add due to rounding.

Reserves Reconciliation

The following table provides a reconciliation of Paramount's gross reserves for the year ended December 31, 2020.

	Proved (1)			**Proved plus Probable** (1)		
	Natural Gas	**Liquids** (2)	**Total**	**Natural Gas**	**Liquids** (2)	**Total**
	(Bcf)	(MBbl)	(MBoe)	(Bcf)	(MBbl)	(MBoe)
December 31, 2019	**1,059.5**	**158,235**	334,817	**1,993.8**	**299,792**	632,097
Extensions/Improved recovery	49.5	7,422	15,672	100.7	18,739	35,523
Technical revisions	52.6	(6,353)	2,410	76.8	2,437	15,236
Economic factors	(54.9)	(7,088)	(16,234)	(84.0)	(11,295)	(25,297)
Dispositions	(1.3)	(119)	(335)	(2.0)	(183)	(521)
Production	(91.0)	(9,841)	(25,013)	(91.0)	(9,841)	(25,013)
December 31, 2020	**1,014.4**	**142,256**	311,317	**1,994.3**	**299,648**	632,025

(1) Columns and rows may not add due to rounding.
(2) Crude oil and NGLs.

Finding and Development Costs [1]

The following table provides a calculation of the Company's PDP finding and development ("F&D") costs for the periods indicated:

	Total F&D Capital [2]	Reserve Additions [3]	F&D	Recycle Ratio [4]
	($ millions)	(MMBoe)	($/Boe)	*(x)*
Proved Developed Producing				
TOTAL COMPANY				
2020	217.9	34.5	**6.31**	1.2x
2019	345.0	33.9	**10.18**	1.2x
3-Year Average	1,085.2	77.8	**13.94**	0.8x
GRANDE PRAIRIE REGION				
2020	196.9	22.0	**8.96**	1.3x
2019	256.7	36.5	**7.03**	2.9x
3-Year Average	719.3	67.6	**10.63**	1.7x

(1) Readers are referred to the advisories concerning Non-GAAP Measures and Oil and Gas Measures and Definitions in the Advisories section of this document.
(2) Total capital expenditures for the year excluding corporate expenditures, land and property acquisitions and, in 2018 and 2019, expenditures of $35.9 million and $45.5 million associated with the expansion of the Karr 6-18 facility that was disposed of in 2019.
(3) Net changes to reserves from the prior year from extensions/improved recoveries, technical revisions and economic factors.
(4) Recycle ratio is calculated by dividing netback per Boe by the applicable finding and development cost.

Finding and development costs have not been presented on a TP and P+P basis due to the fact that the aggregate of total capital expenditures and changes in future development costs were negative. The calculation of finding and development costs utilizing this negative amount would not yield a metric useful in determining the relationship between capital invested in oil and gas exploration and development projects and reserve additions associated with such projects.

LAND

Paramount's land position includes:

	December 31, 2020		December 31, 2019	
(thousands of acres)	**Gross** [1]	**Net** [2]	Gross [1]	Net [2]
Acreage assigned reserves	**868**	**553**	938	569
Acreage not assigned reserves	**2,583**	**1,477**	3,107	1,844
Total	**3,451**	**2,030**	4,045	2,412

(1) "Gross" acres means the total acreage in which Paramount has an interest. Gross acreage is calculated only once per lease or license of petroleum and natural gas rights ("Lease") regardless of whether or not Paramount holds a working and/or royalty interest, or whether or not the Lease includes multiple prospective formations. If Paramount holds interests in different formations beneath the same surface location pursuant to separate Leases, the acreage set out in each Lease is counted. Excludes Cavalier Energy lands.
(2) "Net" acres means gross acres multiplied by Paramount's working interest therein. Excludes Cavalier Energy lands.

CORPORATE

To provide greater certainty of free cash flow levels and the funding of the Company's 2021 capital program, Paramount has hedged approximately 57% of its 2021 forecast production. The Company's current 2021 hedging position is summarized below:

- Natural Gas: approximately 67,400 MMBtu/d at US$2.73/MMBtu and approximately 89,200 GJ/d at CDN$2.53/GJ over 2021.

- Oil: approximately 18,100 Bbl/d at US$46.35/Bbl in 2021 and 3,000 Bbl/d at CDN$65.29/Bbl in the second and third quarters.

- Condensate: 1,000 Bbl/d at WTI plus US$0.50/Bbl in the first quarter and 4,000 Bbl/d at WTI plus US$0.06/Bbl in the second quarter.

Paramount's natural gas diversification strategy includes arrangements to sell approximately 60,000 GJ/d of natural gas at Dawn, approximately 22,000 GJ/d of natural gas at Malin and 40,000 GJ/d of natural gas sales priced in the US Midwest.

In 2020, Paramount implemented a corporate pandemic response plan aimed at ensuring the health and safety of its staff and contractors and the people they come in contact with. The Company is conducting its operations in compliance with public health requirements and guidelines, including by providing additional personal protective equipment and restricting access to its work sites to critical personnel.

Paramount released its inaugural ESG report in 2020 as part of its ongoing commitment to sustainable resource development, environmental stewardship and the wellbeing of its employees and the communities in which it operates. The report is available for review on the Company's website at www.paramountres.com.

The Company's long-term debt at December 31, 2020 was $813 million. In January 2021, Paramount's $1.0 billion senior secured revolving bank credit facility was amended to remove prior conditions on facility availability in excess of $900 million. Concurrent with the amendments, the Company completed a private placement of $35 million of senior unsecured convertible debentures.

Based on Paramount's strong financial and operational performance, in March 2021 the Company elected to exit the covenant relief period under its $1.0 billion bank credit facility prior to the scheduled expiry of the period on June 30, 2021.

The Company successfully closed non-core asset dispositions for cash proceeds of approximately $80 million in the first quarter of 2021. The estimated impact to average 2021 production is approximately 2,600 Boe/d (15 MMcf/d of conventional natural gas and 135 Bbl/d of NGLs).

Management’s Discussion and Analysis
For the year ended December 31, 2020

This Management's Discussion and Analysis ("MD&A"), dated March 2, 2021 should be read in conjunction with the audited consolidated financial statements of Paramount Resources Ltd. ("Paramount" or the "Company") as at and for the year ended December 31, 2020 (the "Consolidated Financial Statements"). Financial data included in this MD&A has been prepared in accordance with International Financial Reporting Standards ("IFRS" or "GAAP") and is stated in millions of Canadian dollars, unless otherwise noted. The Company's accounting policies have been applied consistently to all periods presented.

The disclosures in this document include forward-looking information, non-GAAP financial measures and certain oil and gas measures. Readers are referred to the Advisories section of this document concerning such matters. Certain comparative figures have been reclassified to conform to the current years' presentation. Additional information concerning Paramount, including its Annual Information Form, can be found on the SEDAR website at www.sedar.com.

ABOUT PARAMOUNT

Paramount is an independent, publicly traded, liquids-focused Canadian energy company that explores for and develops both conventional and unconventional petroleum and natural gas reserves and resources. Paramount's principal properties are located in Alberta and British Columbia. Paramount commenced operations as a public company in 1978 and has adapted to a multitude of operating and economic climates over the years. The Company's Class A common shares ("Common Shares") are listed on the Toronto Stock Exchange under the symbol "POU".

Paramount's operations are organized into the following three regions:

- the Grande Prairie Region, located in the Peace River Arch area of Alberta, which is focused on Montney developments at Karr and Wapiti;
- the Kaybob Region, located in west-central Alberta, which includes the Kaybob North and Ante Creek Montney oil developments, Duvernay developments at Kaybob Smoky, Kaybob North and Kaybob South and other shale gas and conventional natural gas producing properties; and
- the Central Alberta and Other Region, which includes the Willesden Green Duvernay development in central Alberta and shale gas producing properties in the Horn River Basin and at Birch in northeast British Columbia.

The Company's assets include: (i) strategic investments in exploration and pre-development stage assets, including prospective shale gas acreage in the Liard Basin, prospective natural gas and oil acreage in the Mackenzie Delta and at Central Mackenzie and interests held by the Company's wholly-owned subsidiary Cavalier Energy Inc. ("Cavalier") prospective for in-situ thermal oil recovery and heavy oil production; (ii) drilling rigs owned by the Company's wholly-owned limited partnership Fox Drilling Limited Partnership ("Fox Drilling"); and (iii) investments in other entities.

NOTE REGARDING PRODUCT TYPES

This MD&A includes references to sales volumes of "natural gas", "condensate and oil" and "Other NGLs" and revenues therefrom. "Natural gas" refers to conventional natural gas and shale gas combined. "Condensate and oil" refers to condensate, light and medium crude oil and tight oil combined. "Other NGLs" refers to ethane, propane and butane. Readers are referred to the Product Type Information section of this document for a complete breakdown of sales volumes and revenues for applicable periods by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

FINANCIAL AND OPERATING HIGHLIGHTS (1)(2)

	2020	2019	2018
FINANCIAL			
Petroleum and natural gas sales	**626.0**	914.9	965.5
Net income (loss)	**(22.7)**	(87.9)	(367.2)
Per share – basic & diluted ($/share)	***(0.17)***	*(0.67)*	*(2.78)*
Cash from operating activities	**80.9**	255.7	223.4
Per share – basic & diluted ($/share)	***0.61***	*1.96*	*1.69*
Adjusted funds flow	**150.0**	299.0	263.9
Per share – basic & diluted ($/share)	***1.12***	*2.29*	*2.00*
Total assets	**3,497.0**	3,531.3	4,118.1
Long-term debt	**813.5**	632.3	815.0
Net debt	**854.1**	703.5	896.0
Total liabilities	**1,459.2**	1,448.1	1,867.6
Common shares outstanding (thousands) (3)	**132,284**	133,337	130,326
OPERATIONAL			
Sales volumes			
Natural gas (MMcf/d)	**248.7**	303.3	325.9
Condensate and oil (Bbl/d)	**22,565**	25,079	24,238
Other NGLs (Bbl/d)	**4,325**	6,767	7,386
Total (Boe/d)	**68,340**	82,394	85,941
Realized prices			
Natural gas ($/Mcf)	**2.25**	2.36	2.25
Condensate and oil ($/Bbl)	**46.47**	66.66	67.81
Other NGLs ($/Bbl)	**15.63**	15.24	30.67
Petroleum and natural gas sales ($/Boe)	**25.03**	30.42	30.78
Total capital expenditures	**220.8**	404.1	580.2

(1) Readers are referred to the advisories concerning Non-GAAP financial measures and Oil and Gas Measures and Definitions in the Advisories section of this document and to the reconciliations of such Non-GAAP financial measures to their most directly comparable measure under GAAP in the applicable sections of this document. This table contains the following Non-GAAP financial measures: Adjusted funds flow, Net debt and Total capital expenditures.

(2) "Natural gas" refers to conventional natural gas and shale gas combined. "Condensate and oil" refers to condensate, light and medium crude oil and tight oil combined. "Other NGLs" refers to ethane, propane and butane. Readers are referred to the Product Type Information section of this document for a complete breakdown of sales volumes and revenues for all applicable periods by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

(3) Common Shares are presented net of shares held in trust under the Company's restricted share unit plan (000's of Common Shares): 2020: 1,914; 2019: 860; 2018: 574.

2020 OVERVIEW

Paramount's financial and operating results for 2020 reflect both the significant impact of the COVID-19 pandemic and the Company's successful response.

On March 4, 2020, Paramount announced initial capital expenditure guidance for 2020 of between $350 million and $450 million and resulting forecast average annual sales volumes of between 75,000 and 80,000 Boe/d. Shortly thereafter, a decline in oil and condensate prices that had begun in late-February due to disputes among members of OPEC+ and growing concerns respecting the potential impact of the COVID-19 pandemic rapidly accelerated. Paramount responded swiftly by announcing on March 19, 2020 a reduction of capital expenditure guidance to a range of between $185 and $250 million and a resulting reduction of forecast average annual sales volumes to a range of between 70,000 and 75,000 Boe/d. Paramount also implemented significant cost reduction initiatives aimed at lowering general and administrative expenses and operating costs, including securing reduced contractor and supplier rates. These initiatives included workforce reductions, a 20 percent reduction in the salary of the President and Chief Executive Officer and in the cash compensation of the Board of Directors, a 10 percent reduction in the salaries of all other staff and the suspension or elimination of a number of benefits and incentive compensation programs. As a further response, Paramount moved to temporarily shut-in certain production at various properties.

Despite the resolution of the OPEC+ disputes in the latter part of the second quarter of 2020, the erosion of global demand for crude oil and petroleum products in connection with the COVID-19 pandemic further negatively and materially impacted the oil and condensate prices received by the Company in the quarter. On May 13, 2020, Paramount revised its 2020 capital expenditure guidance to $165 million and withdrew its sales volume guidance. On June 29, 2020, Paramount's senior secured revolving bank credit facility was amended to provide for a period of financial covenant relief with a decrease in the size of the facility to $1.0 billion, as further described in this MD&A under "Liquidity and Capital Resources".

The third quarter of 2020 saw moderate stabilization and improvement in oil and condensate prices. To capitalize on the strengthening pricing environment and to position itself for a 2021 price recovery, Paramount announced on September 14, 2020 that it was accelerating $60 million of development activities at its Karr and Wapiti properties from 2021 to the second half of 2020. This resulted in 2020 capital expenditure guidance being revised to $225 million and the reinstatement of sales volume guidance for the second half of 2020 of a range between 62,500 and 67,500 Boe/d and for the fourth quarter of a range of between 67,000 and 72,000 Boe/d. By the end of the quarter, the Company had exceeded its 2020 cost reduction targets of $25 million in operating costs and $15 million in general and administrative expenses. In conjunction with the release of its third quarter results on November 5, 2020, the Company announced that it was maintaining its 2020 capital guidance of $225 million and revising fourth quarter forecast sales volumes to a range of between 70,000 and 72,000 Boe/d. The Company also announced that it had largely brought back on production wells that had been shut-in earlier in the year.

Oil and condensate prices continued to recover as the fourth quarter of 2020 progressed and the Company delivered strong operational results while maintaining capital discipline. The continued realization of significant capital costs savings enabled the completion of additional development activities at Karr and Wapiti not contemplated in the capital budget while keeping total 2020 capital expenditures under guidance at $220.8 million. Fourth quarter sales volumes exceeded the upper range of guidance of 72,000 Boe/d, averaging 73,460 Boe/d, as a result of higher than expected production at Karr from the five-well 2-1 pad and the five-well 5-16 West pad.

Throughout 2020, Paramount continued to realize significant cost savings in its capital program by a combination of advancements in well design, drill bit technology, fluid selection and reducing vendor rates. The provincial and federal governments also introduced a variety of measures to provide assistance to businesses. The Company realized $11.1 million of benefits under the Federal Government's Canada Emergency Wage Subsidy (the "CEWS") program in 2020 and received approvals for up to $14 million of funding under the Alberta Site Rehabilitation Program (the "ASRP"), of which $4 million was used in 2020, with the remainder available for use in 2021 and 2022. See "Operating Results", "Corporate" and "Property, Plant and Equipment and Exploration Expenditures" in this MD&A.

PARAMOUNT'S CONTINUING RESPONSE TO THE COVID-19 PANDEMIC

Pricing conditions for oil and condensate have strengthened in the first part of 2021 but remain subject to the impact of the evolving COVID-19 pandemic. Paramount has hedged approximately 57 percent of its forecasted 2021 production to reduce its exposure to price volatility. The Company has flexibility to adjust capital expenditure plans as conditions develop in 2021.

Paramount has implemented a corporate pandemic response plan aimed at ensuring the health and safety of its staff and contractors and the people they come in contact with. The Company is conducting its operations in compliance with public health requirements and guidelines, including by providing additional personal protective equipment and restricting access to its work sites to critical personnel. Paramount has implemented processes to permit its Calgary head office employees to work either remotely or in the office depending on personal circumstances and the public health measures in place from time to time.

Paramount continues to monitor the effect of the COVID-19 pandemic on its supply chain and the availability of third party services. To date, the Company has not experienced a material interruption in supplies or services related to the pandemic.

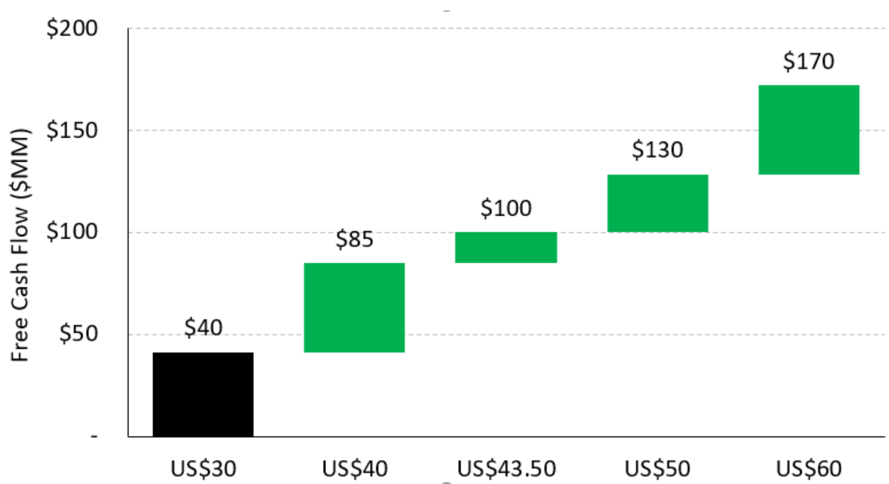
The course of the COVID-19 pandemic and its ultimate economic impact remain highly uncertain. Paramount will continue to proactively respond to the pandemic and the risks that it poses to the Company, including the risks described in this MD&A under "Risk Factors".

2021 GUIDANCE

Paramount's capital budget for 2021 is expected to range between $230 million and $260 million, excluding land acquisitions and abandonment and reclamation activities. Over 60 percent of the capital budget will be incurred in the first half of 2021. Approximately 85 percent of the 2021 program will be focused on advancing the Company's liquids-rich Montney developments at Karr and Wapiti. Approximately 70% of the 2021 capital budget is being allocated to sustaining capital and maintenance activities and the remaining 30% to production growth.

The Company forecasts that 2021 sales volumes will average between 77,000 Boe/d and 80,000 Boe/d (45 percent liquids). First half 2021 sales volumes are expected to average between 74,000 Boe/d and 76,000 Boe/d (43 percent liquids) as the majority of new wells will be brought on later in the year and volumes will be impacted by a scheduled outage at Karr in the second quarter. Despite a scheduled outage at Wapiti in the third quarter, second half 2021 sales volumes are expected to increase to average between 80,000 Boe/d and 84,000 Boe/d (46 percent liquids) as additional liquids-rich wells are brought onstream.[1]

The Company forecasts 2021 free cash flow of approximately $160 million based on: (i) the midpoint of forecast capital spending and production, (ii) $25 million in abandonment and reclamation costs, (iii) realized pricing of $39.50/Boe (US$58.60/Bbl WTI, US$3.00/MMBtu NYMEX, $2.80/GJ AECO), (iv) operating costs of $11.65/Boe, and (v) transportation and processing costs of $4.00/Boe. With approximately 57 percent of forecast midpoint 2021 production hedged, forecast free cash flow would still be approximately $100 million at an average 2021 WTI oil price of US$43.50/Bbl. Below is forecasted free cash flow at alternate average 2021 WTI prices. [2]



(1) Liquids refers to NGLs (including condensate) and oil combined. Readers are referred to the Product Type Information section of this document for more information respecting the composition of forecast sales volumes.

(2) "Free cash flow" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

CONSOLIDATED RESULTS

Net Loss

Paramount recorded a net loss of $22.7 million for the year ended December 31, 2020 compared to a net loss of $87.9 million in the same period in 2019. Significant factors contributing to the change are shown below:

Year ended December 31	
Net loss – 2019	**(87.9)**
• Lower depletion, depreciation and net impairment reversals in 2020, mainly due to net impairment reversals of $141.9 million and lower depletion expense in 2020	252.7
• Lower income tax expense in 2020	102.1
• Gain on financial commodity contracts in 2020 compared to a loss in 2019	54.1
• Lower general and administrative expenses in 2020	19.7
• Closure program costs recognized in 2019	14.0
• Lower accretion expense on asset retirement obligations in 2020	13.3
• Lower netback in 2020, mainly due to lower commodity prices and sales volumes, partially offset by lower operating expense	(184.6)
• Loss on the sale of oil and gas assets in 2020 compared to a gain in 2019	(178.0)
• Lower recovery related to changes in asset retirement obligations in 2020	(16.0)
• Higher interest and financing expenses in 2020	(13.5)
• Other	1.4
Net loss – 2020	**(22.7)**

Paramount recorded a net loss of $87.9 million for the year ended December 31, 2019 compared to a net loss of $367.2 million in the same period in 2018. Significant factors contributing to the change are shown below:

Year ended December 31	
Net loss – 2018	**(367.2)**
• Lower depletion, depreciation and impairment in 2019 mainly due to impairment charges of $502.5 million in 2018	612.4
• Higher gain on the sale of oil and gas assets in 2019	111.9
• Income tax expense in 2019, which included a reduction in Alberta income tax rates, compared to a recovery in 2018	(305.7)
• Loss on financial commodity contracts in 2019 compared to a gain in 2018	(52.2)
• Lower netback in 2019, mainly due to lower liquids prices and lower natural gas sales volumes, partially offset by higher natural gas prices	(41.4)
• Closure program costs recognized in 2019	(14.0)
• Lower recovery related to changes in asset retirement obligations in 2019	(12.9)
• Other	(18.8)
Net loss – 2019	**(87.9)**

Cash From Operating Activities

Cash from operating activities for the year ended December 31, 2020 was $80.9 million compared to $255.7 million for the same period in 2019. Significant factors contributing to the change are shown below:

Year ended December 31	
Cash from operating activities – 2019	**255.7**
• Lower netback in 2020, mainly due to lower commodity prices and sales volumes, partially offset by lower operating expense	(184.6)
• Change in non-cash working capital	(33.8)
• Higher interest and financing expenses in 2020	(12.3)
• Higher asset retirement obligation settlements in 2020	(5.6)
• Higher receipts on financial commodity contract settlements in 2020	24.4
• Lower general and administrative expenses in 2020	19.7
• Closure program costs recognized in 2019	14.0
• Other	3.4
Cash from operating activities – 2020	**80.9**

Cash from operating activities for the year ended December 31, 2019 was $255.7 million compared to $223.4 million for the same period in 2018. Significant factors contributing to the change are shown below:

Year ended December 31	
Cash from operating activities – 2018	**223.4**
• Receipts on financial commodity contract settlements in 2019 compared to payments in 2018	89.7
• Lower netback in 2019, mainly due to lower liquids prices and lower natural gas sales volumes, partially offset by higher natural gas prices	(41.4)
• Closure program costs recognized in 2019	(14.0)
• Other	(2.0)
Cash from operating activities – 2019	**255.7**

Adjusted Funds Flow (1)

The following is a reconciliation of adjusted funds flow to the nearest GAAP measure:

Year ended December 31	2020	2019	2018
Cash from operating activities	**80.9**	255.7	223.4
Change in non-cash working capital	**17.9**	(15.9)	(7.0)
Geological and geophysical expenses	**8.5**	11.0	12.5
Asset retirement obligations settled	**35.0**	29.4	29.4
Closure costs	**–**	14.0	–
Provision and other	**4.7**	2.5	–
Transaction and reorganization costs	**3.0**	2.3	5.6
Adjusted funds flow	**150.0**	299.0	263.9
Adjusted funds flow (*$/Boe*)	**6.00**	9.94	8.41

(1) "Adjusted funds flow" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

Adjusted funds flow for the year ended December 31, 2020 was $150.0 million compared to $299.0 million for the year ended 2019. Significant factors contributing to the change are shown below:

Year ended December 31	
Adjusted funds flow – 2019	**299.0**
• Lower netback in 2020, mainly due to lower commodity prices and lower sales volumes, partially offset by lower operating expense	(184.6)
• Higher interest and financing expenses in 2020	(12.3)
• Higher receipts on financial commodity contract settlements in 2020	24.4
• Lower general and administrative expenses in 2020	19.7
• Other	3.8
Adjusted funds flow – 2020	**150.0**

Adjusted funds flow for the year ended December 31, 2019 was $299.0 million compared to $263.9 million for the same period in 2018. Significant factors contributing to the change are shown below:

Year ended December 31	
Adjusted funds flow – 2018	**263.9**
• Receipts on financial commodity contract settlements in 2019 compared to payments in 2018	89.7
• Lower netback in 2019, mainly due to lower liquids prices and lower natural gas sales volumes, partially offset by higher natural gas prices	(41.4)
• Higher interest and financing expenses in 2019	(9.2)
• Other	(4.0)
Adjusted funds flow – 2019	**299.0**

OPERATING RESULTS

Netback [(1)]

Year ended December 31	**2020**		2019	
		($/Boe) [(2)]		*($/Boe)* [(2)]
Natural gas revenue	**204.9**	***2.25***	261.0	*2.36*
Condensate and oil revenue	**383.8**	***46.47***	610.2	*66.66*
Other NGLs revenue [(3)]	**24.7**	***15.63***	37.7	*15.24*
Royalty and other revenue	**12.6**	**–**	6.0	–
Petroleum and natural gas sales	**626.0**	***25.03***	914.9	*30.42*
Royalties	**(31.3)**	***(1.25)***	(63.3)	*(2.10)*
Operating expense	**(297.1)**	***(11.88)***	(376.0)	*(12.50)*
Transportation and NGLs processing [(4)]	**(101.3)**	***(4.05)***	(94.7)	*(3.15)*
Netback	**196.3**	***7.85***	380.9	*12.67*
Financial commodity contract settlements	**37.6**	***1.50***	13.2	*0.44*
Netback including financial commodity contract settlements	**233.9**	***9.35***	394.1	*13.11*

(1) "Netback" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.
(2) Natural gas revenue shown per Mcf.
(3) Other NGLs means ethane, propane and butane.
(4) Includes downstream natural gas, NGLs and oil transportation costs and NGLs fractionation costs.

Petroleum and natural gas sales were $626.0 million in 2020, a decrease of $288.9 million from the prior year due to lower commodity prices and sales volumes.

The impact of changes in sales volumes and prices on petroleum and natural gas sales are as follows:

	Natural Gas	Condensate and Oil	Other NGLs	Royalty and Other	Total
Year ended December 31, 2019	261.0	610.2	37.7	6.0	914.9
Effect of changes in sales volumes	(46.4)	(59.7)	(13.5)	–	(119.6)
Effect of changes in prices	(9.7)	(166.7)	0.5	–	(175.9)
Change in royalty and other revenue	–	–	–	6.6	6.6
Year ended December 31, 2020	**204.9**	**383.8**	**24.7**	**12.6**	**626.0**

Petroleum and natural gas sales were $914.9 million in 2019, a decrease of $50.6 million from 2018 mainly due to lower liquids prices and lower natural gas and other NGLs sales volumes, partially offset by higher natural gas prices.

The impact of changes in sales volumes and prices on petroleum and natural gas sales are as follows:

	Natural Gas	Condensate and oil	Other NGLs	Royalty and Other	Total
Year ended December 31, 2018	267.1	599.9	82.7	15.8	965.5
Effect of changes in sales volumes	(18.5)	20.8	(6.9)	–	(4.6)
Effect of changes in prices	12.4	(10.5)	(38.1)	–	(36.2)
Change in royalty and other revenue	–	–	–	(9.8)	(9.8)
Year ended December 31, 2019	**261.0**	**610.2**	**37.7**	**6.0**	**914.9**

Sales Volumes (1)

	Year ended December 31											
	Natural Gas (MMcf/d)			Condensate and Oil (Bbl/d)			Other NGLs (Bbl/d)			Total (Boe/d)		
	2020	2019	*% Change*	**2020**	2019	*% Change*	**2020**	2019	*% Change*	**2020**	2019	*% Change*
Grande Prairie	**78.6**	79.5	*(1)*	**16,005**	13,973	*15*	**1,964**	1,814	*8*	**31,076**	29,040	*7*
Kaybob	**125.9**	146.2	*(14)*	**5,895**	8,650	*(32)*	**1,812**	2,476	*(27)*	**28,685**	35,500	*(19)*
Central Alberta & Other	**44.2**	77.6	*(43)*	**665**	2,456	*(73)*	**549**	2,477	*(78)*	**8,579**	17,854	*(52)*
Total	**248.7**	303.3	*(18)*	**22,565**	25,079	*(10)*	**4,325**	6,767	*(36)*	**68,340**	82,394	*(17)*

(1) Readers are referred to the Product Type Information section of this document for more information respecting the composition of sales volumes by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

Sales volumes were 68,340 Boe/d for the year ended December 31, 2020, compared to 82,394 Boe/d in the same period in 2019. The decrease was primarily due to the sale of certain natural gas-weighted properties in West Central Alberta (the "West Central Alberta Assets") in late-2019 and natural declines in the Kaybob Region where the Company deployed limited capital in 2020 to focus on more profitable developments at Karr and Wapiti in the Grande Prairie Region. In December 2019, Paramount closed the sale of the West Central Alberta Assets for gross cash proceeds of approximately $52.4 million. The West Central Alberta Assets were included in the Central Alberta & Other Region and had average sales volumes of approximately 8,500 Boe/d (30.6 MMcf/d of conventional natural gas, 2,947 Bbl/d of NGLs and 466 Bbl/d of light and medium crude oil) and a netback of approximately $22.5 million in 2019 prior to the date of sale.

The decreases in sales volumes in 2020 in the lower netback Central Alberta & Other and Kaybob Regions were partially offset by higher sales volumes in the liquids rich Grand Prairie Region. Sales volumes at Wapiti increased from 6,082 Boe/d (10.8 MMcf/d of shale gas, 0.3 MMcf/d of conventional gas and 4,223 Bbl/d of NGLs) in 2019 to 10,207 Boe/d (21.5 MMcf/d of shale gas, 0.4 MMcf/d of conventional natural gas and 6,550 Bbl/d of NGLs) in 2020, primarily as a result of a full year of production following the start-up of the new third-party Wapiti natural gas processing plant in May 2019 (the "Wapiti Plant"). 2020 Wapiti sales volumes were impacted by about 2,200 Boe/d due to approximately 10 weeks of downtime at the Wapiti Plant. At Karr, sales volumes were 20,777 Boe/d (55.6 MMcf/d of shale gas, 0.7 MMcf/d of conventional natural gas and 11,389 Bbl/d of NGLs) in 2020 compared to 22,755 Boe/d (67.2 MMcf/d of shale gas, 0.5 MMcf/d of conventional natural gas and 11,477 Bbl/d of NGLs) in 2019, reflecting the impact of deferred capital activities in 2020 and the effects of gathering system constraints. Paramount completed a debottlenecking project in the third quarter to alleviate these gathering system constraints.

Commodity Prices

Year Ended December 31	2020	2019	% Change
Natural Gas			
Paramount realized natural gas price ($/Mcf)	**2.25**	2.36	(5)
AECO daily spot ($/GJ)	**2.11**	1.67	*26*
AECO monthly index ($/GJ)	**2.12**	1.54	38
Dawn ($/MMbtu)	**2.51**	3.22	*(22)*
NYMEX (US$/MMbtu)	**2.13**	2.53	*(16)*
Malin – monthly index (US$/MMbtu)	**2.15**	2.67	*(19)*
Condensate and Oil			
Paramount realized condensate & oil price ($/Bbl)	**46.47**	66.66	*(30)*
Edmonton light sweet crude oil ($/Bbl)	**45.39**	68.87	*(34)*
West Texas Intermediate crude oil (US$/Bbl)	**39.40**	57.02	*(31)*
Other NGLs (1)			
Paramount realized Other NGLs price ($/Bbl) (1)	**15.63**	15.24	*3*
Conway – propane ($/Bbl)	**24.83**	26.43	*(6)*
Belvieu – butane ($/Bbl)	**30.48**	35.95	*(15)*
Foreign Exchange			
$CDN / 1 $US	**1.34**	1.33	*1*

(1) Other NGLs means ethane, propane and butane.

Paramount's natural gas portfolio primarily consists of sales priced at Alberta, California, Chicago, Ventura and Eastern Canada markets, which are sold in a combination of daily, monthly and seasonal contracts. The Company's natural gas portfolio includes arrangements to sell approximately 60,000 GJ/d of natural gas at Dawn, approximately 22,000 GJ/d of natural gas at Malin and 40,000 GJ/d of natural gas sales priced in the US Midwest.

The Company had the following AECO fixed-price physical contracts to sell natural gas in place at December 31, 2020:

Quantity	Location	Average fixed price	Remaining term
40,000 GJ/d	AECO	CDN$2.68/GJ	January 2021 - March 2021
50,000 GJ/d	AECO	CDN$2.51/GJ	January 2021 - December 2021

Subsequent to December 31, 2020, the Company entered into the following AECO fixed-price physical contracts to sell natural gas:

Quantity	Location	Average fixed price	Remaining term
50,000 GJ/d	AECO	CDN$2.52/GJ	April 2021- October 2021

Paramount ships a portion of its condensate and crude oil production on third-party pipelines for sale in Edmonton, Alberta, where volumes sold generally receive higher prices due to the greater diversity of potential purchasers. A limited portion of the Company's production continues to be sold at truck terminals or at the lease when warranted by economic or operational factors. Sales prices for condensate and oil are based on West Texas Intermediate reference prices, adjusted for transportation, quality and density differentials.

The Company's butane and propane volumes are generally sold under contracts that are renewed annually in April each year. The contracts in place in 2020 had more favorable differentials to West Texas Intermediate reference prices than in 2019.

Financial Commodity Contracts

From time-to-time Paramount uses financial commodity contracts to manage exposure to commodity price volatility. Changes in the fair value of the Company's financial commodity contracts are as follows:

Year ended December 31	2020	2019
Fair value, beginning of year	6.1	64.4
Changes in fair value	8.8	(45.1)
Settlements received	(37.6)	(13.2)
Fair value, end of year	(22.7)	6.1

For further details on the Company's financial commodity contracts, refer to Note 14 of the Consolidated Financial Statements.

Subsequent to December 31, 2020, the Company entered into the following financial commodity contracts:

Instruments	Aggregate notional	Average fixed price	Remaining term
Oil – NYMEX WTI Swaps (Sale)	3,000 Bbl/d	CDN$65.29/Bbl	April 2021 – September 2021
Oil – NYMEX WTI Swaps (Sale)	4,573 Bbl/d	US$58.52/Bbl	February 2021 – June 2021
Oil – Edmonton Condensate WTI Differential Swap (Sale)	4,000 Bbl/d	WTI + US$0.06/Bbl	April 2021 – June 2021

The following table summarizes the Company's 2021 financial commodity contracts and fixed-price physical contracts:

	Type [1]	Q1 2021	Q2 2021	Q3 2021	Q4 2021	Average Price [2]
Oil –WTI Swaps (Sale) (Bbl/d)	Financial	24,589	23,000	15,000	10,000	US$46.35/Bbl
Oil – WTI Swap (Sale) (Bbl/d)	Financial	–	3,000	3,000	–	C$65.29/Bbl
Condensate – Basis Swap (Sale) (Bbl/d)	Financial	1,000	4,000	–	–	WTI + US$0.15/Bbl
Gas – NYMEX Swaps (Sale) (MMbtu/d)	Financial	90,000	60,000	60,000	60,000	US$2.73/MMbtu
Gas – AECO fixed price (GJ/d)	Physical	90,000	100,000	100,000	66,848	C$2.53/GJ

(1) Financial, refers to financial commodity contracts. Physical, refers to fixed-priced physical contracts.
(2) Average price is calculated using weighted average notional volumes and prices.

Royalties

Year ended December 31	2020	Rate	2019	Rate
Royalties	**31.3**	**5.1%**	63.3	7.0%
$/Boe	***1.25***		*2.10*	

Royalties were $31.3 million for the year ended December 31, 2020, $32.0 million lower than the same period in 2019, primarily as a result of lower condensate and oil prices and decreased sales volumes.

Operating Expense

Year ended December 31	2020	2019	% Change
Operating expense	**297.1**	376.0	*(21)*
$/Boe	***11.88***	*12.50*	*(5)*

Operating expense was $297.1 million for the year ended December 31, 2020, $78.9 million lower than the same period in 2019.

Operating costs in 2020 were lower compared to the same period in 2019 primarily due to lower production in the Central and Other and Kaybob Regions and as a result of the Company's response to the decreased oil and condensate prices as described in this MD&A under "2020 Overview", which included decreased labour costs, supplier cost savings and lower maintenance costs. The Company also realized cost reductions from the closure of the Zama property, new water disposal wells and lower power costs.

The decreases in operating expenses in 2020 were partially offset by higher operating costs in the Grande Prairie Region as a result of incremental processing fees following the start-up of the Wapiti Plant in May 2019 and the sale of the Karr 6-18 natural gas facility in August 2019 (the "Midstream Transaction").

Operating costs were $11.88 per Boe for the twelve months ended December 31, 2020 compared to $12.50 per Boe in the same period of 2019. The decrease in operating expense per Boe is mainly due to the changes described above.

Transportation and NGLs Processing

Year ended December 31	2020	2019	% Change
Transportation and NGLs processing	**101.3**	94.7	7
$/Boe	***4.05***	*3.15*	*29*

Transportation and NGLs processing expense was $101.3 million for the year ended December 31, 2020 compared to $94.7 million in the same period in 2019. Transportation and NGLs processing costs increased in 2020 mainly as a result of higher contracted capacity for Wapiti and Karr, partially offset by lower production in the Central and Other and Kaybob Regions.

Other Operating Items

Year ended December 31	2020	2019
Depletion and depreciation (excluding net impairment reversals)	**(253.9)**	(364.8)
Net impairment reversals of property plant and equipment	**141.9**	–
Gain (loss) on sale of oil and gas assets	**(8.7)**	169.3
Exploration and evaluation expense	**(34.0)**	(22.4)

Depletion and depreciation expense decreased to $253.9 million in 2020 compared to $364.8 million in 2019, mainly due to lower sales volumes and lower depletion rates following impairment charges of $191.8 million recorded in the first quarter of 2020.

At December 31, 2020, the Company recorded aggregate impairment reversals of $333.7 million from previously recorded impairment charges, comprised of $287.7 million, $30.6 million and $15.4 million related to petroleum and natural gas assets in the Kaybob, Northern and Central Alberta cash-generating units ("CGUs"), respectively. The impairment reversals resulted from an increase in the estimated recoverable amount of such CGUs compared to the prior impairment assessment performed at March 31, 2020.

The $333.7 million aggregate impairment reversals represent the amount to bring the carrying values of the Kaybob and Northern CGUs to their estimated recoverable amounts and the carrying value of the Central Alberta CGU to the amount, net of depletion and amortization, had no impairment charges been recognized in prior periods. The increase in the estimated recoverable amount of these CGUs was mainly due to lower operating and capital costs than previously forecasted and changes to the development plan.

The recoverable amount of the Kaybob, Northern and Central Alberta CGUs as at December 31, 2020 was estimated on a fair value less costs of disposal ("FVLCD") basis, using a discounted cash flow method (level 3 fair value hierarchy estimate). Cash flows were projected over the expected remaining productive life of the proved plus probable reserves assigned to the Kaybob, Northern and Central Alberta CGUs, at discount rates of 11.5 percent, 13.5 percent and 13.0 percent, respectively. Proved plus probable reserves estimates were prepared by Paramount's independent qualified reserves evaluator. The reserves evaluation process is inherently subjective and involves considerable estimation uncertainty.

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at December 31, 2020: [(1)]

(Average for the period)	2021	2022	2023	2024	2025	2026-2033	Thereafter
Natural Gas [(2)]							
AECO ($/MMBtu)	2.78	2.70	2.61	2.65	2.70	2.76 – 3.16	+2%/yr
Henry Hub (US$/MMBtu)	2.83	2.87	2.90	2.96	3.02	3.08 – 3.53	+2%/yr
Crude Oil and Condensate [(2)]							
Edmonton Condensate ($/Bbl)	59.24	63.19	67.34	69.77	71.18	72.61 – 83.44	+2%/yr
WTI (US$/Bbl)	47.17	50.17	53.17	54.97	56.07	57.19 – 65.70	+2%/yr
Foreign Exchange							
$US / 1 $CDN	0.77	0.77	0.76	0.76	0.76	0.76	0.76

(1) Average of forecasts published by: (i) McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. at January 1, 2021 and (ii) Sproule Associates Ltd. at December 31, 2020.
(2) Forecast benchmark prices are adjusted for quality differentials, heat content, distance to market and other factors in determining estimated recoverable amounts.

The following table summarizes the impact of a change to the discount rate or before tax undiscounted cash flow estimates on the net impairment reversals as at December 31, 2020:

	Discount Rate		Cash Flow Estimates	
	One Percent Increase	One Percent Decrease	Five Percent Increase	Five Percent Decrease
Net impairment reversals – increase (decrease)	(55,455)	62,102	38,432	(38,432)

At March 31, 2020, the Company recorded impairments of $188.3 million and $3.5 million related to petroleum and natural gas assets in the Kaybob and Northern CGUs, respectively. The impairments were recorded because the carrying value of the CGUs exceeded their estimated recoverable amount, which were estimated based on expected net cash flows from the production of proved plus probable reserves ascribed to each CGU. The impairments resulted from decreases in estimated future net revenues, mainly due to lower forecasted oil and natural gas prices.

Recoverable amounts were estimated on a FVLCD basis using a discounted cash flow method (level three fair value hierarchy estimate). Cash flows were determined based on internally estimated after-tax discounted future net cash flows from the production of proved plus probable reserves assigned to the Kaybob and Northern CGUs, at discount rates of 11.5 percent and 13.5 percent, respectively. The net cash flows from the proved plus probable reserves estimated by Paramount's independent qualified reserves evaluator as at December 31, 2019 were internally updated by Management to reflect commodity price estimates at March 31, 2020 and for changes to certain operating and capital assumptions to reflect the prevailing economic environment. The reserves evaluation process is inherently subjective and involves considerable estimation uncertainty.

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at March 31, 2020 [1]:

	(Apr-Dec) 2020	2021	2022	2023	2024	2025-2032	Thereafter
Natural Gas [2]							
AECO ($/MMBtu)	1.74	2.20	2.38	2.45	2.53	2.60-3.04	+2%/yr
Henry Hub (US$/MMBtu)	2.10	2.58	2.79	2.86	2.93	3.00-3.45	+2%/yr
Crude Oil and Condensate [2]							
Edmonton Condensate ($/Bbl)	34.35	50.72	62.80	68.49	71.73	73.16-84.23	+2%/yr
WTI (US$/Bbl)	29.17	40.45	49.17	53.28	55.66	56.87-65.33	+2%/yr
Foreign Exchange							
$US / 1 $CDN	0.71	0.73	0.75	0.75	0.75	0.75	0.75

(1) Average of forecasts published by: (i) McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. at April 1, 2020 and (ii) Sproule Associates Ltd. at March 31, 2020.
(2) Forecast benchmark prices are adjusted for quality differentials, heat content, distance to market and other factors in determining estimated recoverable amounts.

In August 2019, Paramount closed the Midstream Transaction for gross cash proceeds of $331.6 million. The cash proceeds included the reimbursement of capital expenditures related to the expansion of the 6-18 Facility. In connection with the sale, the Company entered into a midstream services agreement that includes a fee-for-service arrangement and a take-or-pay volume commitment that ends in 2040. A gain of $153.6 million was recognized on the sale.

Exploration and Evaluation ("E&E") expense was $34.0 million in 2020, an increase of $11.6 million compared to 2019, primarily due to higher expenses for expired mineral leases.

DISSENT PAYMENT ENTITLEMENT

As at December 31	2020	2019
Dissent Payment Entitlement	89.3	–

Paramount held 85 million common shares of Strath Resources Ltd. ("Strath") prior to its amalgamation with Cona Resources Ltd. in August 2020 to form Strathcona Resources Ltd. ("Strathcona"). Paramount objected to the amalgamation and exercised its right of dissent under section 191 of the Business Corporations Act (Alberta) (the "ABCA") with respect to its Strath shares. As a result, the Company is entitled to be paid in cash the fair value of its Strath shares, determined as of the close of business on July 24, 2020 (the "Dissent Payment Entitlement").

The amount of the Dissent Payment Entitlement and the timing of the payment thereof are uncertain. Paramount has applied to the Court of Queen's Bench of Alberta (the "Court") seeking Strathcona's payment of the Dissent Payment Entitlement. Strathcona made a statutorily required offer with respect to the Dissent Payment Entitlement in the amount of $45 million (the "Offered Amount"). Paramount has rejected such offer and applied to the Court for an interim payment of the Offered Amount pending final determination of the amount of the Dissent Payment Entitlement. In the event the parties are unable to agree on the amount of the Dissent Payment Entitlement, the final amount, including any interest thereon, will be determined by the Court. Any payment of the Dissent Payment Entitlement will be subject to the satisfaction by Strathcona of the solvency tests provided in the ABCA.

The Dissent Payment Entitlement is a financial instrument measured at amortized cost and was recorded based on valuation techniques and assumptions that incorporate unobservable inputs (level three fair value hierarchy inputs), including market-based metrics of comparable companies and transactions and other indicators of value.

INVESTMENTS IN SECURITIES

As at December 31	2020	2019
Level one fair value hierarchy securities	48.4	88.4
Level three fair value hierarchy securities	11.1	68.5
	59.5	156.9

Paramount holds investments in a number of publicly-traded and private corporations as part of its portfolio of investments.

Investments that are categorized as level one fair value hierarchy securities ("Level One Securities") are carried at their period-end trading prices. Estimates of fair values for investments that are categorized as level three fair value hierarchy securities ("Level Three Securities") are based on valuation techniques that incorporate unobservable inputs. The valuation techniques utilize market-based metrics of comparable companies and transactions, indications of value based on equity transactions of the entities and other indicators of value including financial and operating results of the entities. Fair value estimates of Level Three Securities are updated at each balance sheet date to confirm whether the carrying value of the investment continues to fall within a range of possible fair values indicated by such techniques.

For the year ended December 31, 2020 the Company recorded a charge of $18.1 million to other comprehensive income ("OCI") as a result of changes in the fair value estimates of investments in Level One Securities and investments in Level Three Securities.

For the twelve months ended December 31, 2020, the Company recorded a loss of $1.7 million to net loss related to a change in the estimated fair value of warrants. Accumulated losses of $83.9 million were reclassified from accumulated OCI to accumulated deficit, which included $69.9 million related to the Company’s exercise of its Strath dissent rights.

In 2020, the Company acquired 17.3 million common shares of NuVista Energy Ltd. ("NuVista Shares") at a price of $0.61 per share for an aggregate purchase price of $10.6 million. At December 31, 2020, the Company owned a total of 39.8 million NuVista Shares, representing 17.6 percent of the outstanding NuVista Shares, which were included in Investments in Securities and classified as Level One Securities.

In 2019, Paramount sold a portion of its investment in MEG Energy Corp. for cash proceeds of $13.6 million. As a result of the sale, $61.8 million of accumulated losses were reclassified from accumulated OCI to retained earnings.

Changes in the fair value of investments in securities are as follows:

Year ended at December 31	2020	2019 (1)
Investments in securities, beginning of year	156.9	231.7
Changes in fair value of Level One Securities – recorded in OCI	(50.6)	6.3
Changes in fair value of Level Three Securities (2) – recorded in OCI	32.5	(118.1)
Transfer to Dissent Payment Entitlement	(89.3)	–
Changes in fair value of warrants (3) – recorded in earnings	(1.7)	(9.2)
Acquired – cash	11.7	55.1
Acquired – non-cash	–	4.5
Dispositions	–	(13.6)
Investments in securities, end of year	59.5	156.9

(1) Column does not add due to rounding.
(2) Primarily related to the change in fair value of Strath common shares.
(3) Strathcona warrants (previously the Strath warrants).

ASSET RETIREMENT OBLIGATIONS

The area-based closure program introduced by the Alberta Energy Regulator in September 2018 allows companies to approach abandonment and reclamation activities in an efficient and cost-effective manner by targeting efforts in a concentrated area. Paramount's strategy is to utilize the advantages of the area-based closure program by focusing its abandonment and reclamation activities on the Hawkeye property, which was shut-in in 2018, and the Zama property, which was shut-in in 2019.

Abandonment and reclamation expenditures in 2020 totaled $35 million. In addition, approximately $4 million of activities were funded by the ASRP. Activities included the abandonment of 254 inactive wells, 236 of which were abandoned under the Company's ongoing area-based closure program at the Hawkeye and Zama properties.

The Company has budgeted approximately $31 million of abandonment and reclamation activities in 2021. Approximately $6 million is to be funded directly under the ASRP, resulting in approximately $25 million net to Paramount. The majority of 2021 closure activities will be performed at the Zama property.

As at December 31, 2020, estimated undiscounted, uninflated asset retirement obligations were $1,351.7 million (December 31, 2019 – $1,381.5 million). As at December 31, 2020, the Company's discounted asset retirement obligations were $419.5 million (discounted at 11.0 percent and using an inflation rate of 2.0 percent) compared to $569.9 million as at December 31, 2019 (discounted at 8.0 percent and using an inflation rate of 2.0 percent). For further details concerning the Company's asset retirement obligations, refer to the Consolidated Financial Statements.

OTHER ASSETS

Fox Drilling

Fox Drilling owns seven triple-sized drilling rigs, including four walking rigs, that are used to drill Company wells. The walking rigs have the capability of moving across a lease with the derrick and drill pipe remaining vertical, significantly increasing efficiencies when drilling multi-well pads.

Cavalier Energy

As at December 31, 2020, Cavalier Energy held approximately 1.354 million gross (1.307 million net) acres of land located primarily in the Athabasca and Peace River regions of Alberta. Cavalier Energy's lands are prospective for in-situ thermal oil recovery and heavy oil but are at the early stages of their development.

CORPORATE

Year ended December 31	2020	2019
General and administrative	(32.9)	(52.6)
Share-based compensation	(13.0)	(18.5)
Interest and financing	(53.7)	(40.2)
Accretion of asset retirement obligations	(43.4)	(56.7)
Change in asset retirement obligations	91.3	107.3
Closure costs	–	(14.0)
Dispute settlements	–	(2.5)
Deferred income tax expense	(10.2)	(112.3)

General and administrative and share-based compensation expenses were lower for the year ended December 31, 2020 compared to the same period in 2019 primarily due to cost reduction initiatives, including workforce and salary reductions and the suspension or elimination of a number of benefits and incentive compensation programs. General and administrative expense in 2020 was reduced by $6.4 million as a result of the Company's claim of benefits under the CEWS program.

Interest and financing expense was $53.7 million in 2020, an increase of $13.5 million compared to 2019, as a result of higher average debt balances and interest rates under the Paramount Facility (as described below).

For the year ended December 31, 2020, the Company recorded a recovery of $91.3 million (2019 - $107.3 million recovery) to earnings mainly related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value. In 2020, the changes mainly resulted from revisions in the credit-adjusted risk-free rate used to discount obligations. The changes in 2019 were a result of revisions to the estimated costs and timing of retirement.

In early 2019, Paramount made the decision to cease production operations at its Zama property in the Central Alberta and Other Region. Sales volumes at Zama averaged approximately 1,200 Boe/d (2.3 MMcf/d of conventional natural gas, 30 Bbl/d of NGLs and 817 Bbl/d of light and medium crude oil) in the fourth quarter of 2018. The Company recognized a provision of $14.0 million in 2019 in respect of the expected costs of the Zama closure program, of which the entire $14.0 million had been incurred to December 31, 2019.

The Company recognized a charge of $2.5 million in the fourth quarter of 2019 in respect of two legal disputes. For further details, refer to the Consolidated Financial Statements.

Deferred income tax expense for 2019 included a charge of approximately $101.2 million related to a reduction in Alberta income tax rates.

Tax Pools

At December 31, 2020, Paramount had approximately $3.5 billion of non-capital loss and scientific research and experimental development pools, $1.3 billion of Canadian resource and undepreciated capital cost pools and $0.1 billion of financing cost and other pools.

PROPERTY, PLANT AND EQUIPMENT AND EXPLORATION EXPENDITURES

Year ended December 31	2020	2019
Drilling, completion and tie-ins	199.5	297.7
Facilities and gathering (1)	18.4	92.8
Corporate	2.3	6.0
Land and property acquisitions	0.6	7.6
Total capital expenditures (2)	220.8	404.1
Grande Prairie Region (1)	196.9	302.2
Kaybob Region	16.4	80.7
Central Alberta and Other Region	4.6	7.6
Corporate	2.3	6.0
Land and property acquisitions	0.6	7.6
Total capital expenditures (2)	220.8	404.1

(1) Total capital expenditures for the year ended December 31, 2019 includes $45.5 million of capital spending related to the Karr 6-18 natural gas facility prior to its sale.
(2) "Total capital expenditures" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.

Total capital expenditures were $220.8 million for the year ended December 31, 2020 compared to $404.1 million in the same period of 2019.

Activities in 2020 mainly related to drilling and completion programs in the Grande Prairie Region.

Significant capital program activities undertaken in 2020 are described below:

- At Karr, the Company drilled 15 (15.0 net) Montney wells, completed 15 (15.0 net) wells and brought 15 (15.0 net) wells on production in 2020. Paramount brought into service two new water disposal wells that have decreased operating costs by reducing the need to truck and dispose of water at third-party facilities. In addition, gas lift and related compression at pads near the southwest terminus of the Karr gathering system were installed to mitigate the impact from new higher-pressure wells upstream. In the fourth quarter, the Company brought onstream 5 (5.0 net) Montney wells and drilled 6 (6.0 net) wells.

- At Wapiti, Paramount drilled 8 (8.0 net) Montney wells, completed 5 (5.0 net) wells and brought 6 (6.0 net) wells on production wells in 2020. In the fourth quarter, the Company brought onstream 5 (5.0 net) Montney wells and drilled 1 (1.0 net) wells.

- In the Kaybob Region, Paramount drilled 1 (1.0 net) Montney oil appraisal well at Ante Creek.

- In the Central and Other Region, 1 (0.5 net) well was completed at the Company's non-operated Birch property in British Columbia.

Paramount reduced average per well lease construction, drilling, completion and tie-in costs in 2020 compared to 2019 by approximately 37 percent at Karr and 21 percent at Wapiti. The reductions were driven by improvements in well design, drill bit technology, fluid selection and reducing vendor rates. Cost savings in Paramount's capital program allowed the completion of additional unbudgeted development activities at Karr and Wapiti in 2020 without exceeding total capital expenditure guidance.

LIQUIDITY AND CAPITAL RESOURCES

Paramount's primary objectives in managing its capital structure are to:

i. maintain a flexible capital structure which optimizes the cost of capital at an acceptable level of risk;

ii. maintain sufficient liquidity to support ongoing operations, capital expenditure programs, strategic initiatives and the settlement of obligations when due; and

iii. maximize shareholder returns.

Paramount manages its capital structure to support current and future business plans and periodically adjusts the structure in response to changes in economic conditions and the risk characteristics of the Company's underlying assets and operations. Paramount may adjust its capital structure through a number of means, including by issuing or repurchasing shares, altering debt levels, modifying capital spending programs, acquiring or disposing of assets and participating in joint ventures and farm-ins and farm-outs, the availability of any such means being dependent upon market conditions.

As at December 31	**2020**	**2019**
Cash and cash equivalents	**(4.6)**	(6.0)
Accounts receivable (1)	**(97.7)**	(116.6)
Prepaid expenses and other	**(9.9)**	(11.0)
Accounts payable and accrued liabilities	**152.8**	204.8
Adjusted working capital deficit (1) (2)	**40.6**	71.2
Long-term debt	**813.5**	632.3
Net debt (2)	**854.1**	703.5
Share capital	**2,207.4**	2,207.5
Accumulated deficit	**(235.1)**	(128.5)
Reserves	**65.4**	4.2
Total Capital	**2,891.8**	2,786.7

(1) Adjusted working capital excludes risk management assets and liabilities, current accounts receivable relating to subleases (December 31, 2020 - $2.3 million, December 31, 2019 – $2.0 million) and the current portion of asset retirement obligations and other.
(2) "Adjusted working capital deficit" and "Net debt" are Non-GAAP financial measures. See "Non-GAAP Financial Measures" in the Advisories section.

Paramount's operations are capital intensive and adequate sources of liquidity are required to fund ongoing exploration and development activities, discharge asset retirement obligations and satisfy contractual commitments. Paramount's available capital resources include adjusted funds flow and available capacity under its senior secured revolving bank credit facility (the "Paramount Facility"), the terms of which are described further below.

Based on the forecasts of 2021 sales volumes and the pricing assumptions set out in this MD&A under "2021 Guidance", Paramount expects to fully fund budgeted capital expenditures of between $230 million and $260 million and net budgeted expenditures for abandonment and reclamation activities of $25 million from cash from operating activities. Paramount may utilize borrowing capacity under the Paramount Facility for liquidity from time to time to fund operations during periods of the year in which expenditures exceed cash from operating activities.

The ability of cash from operating activities to satisfy the Company's funding requirements in 2021 and future years is dependent on a number of factors, including commodity prices, sales volumes, royalties, operating and transportation costs, general and administrative and interest expenses and foreign exchange rates.

Paramount may also determine to divest of assets or investments in securities from time to time to reduce indebtedness or fund operations. In the first quarter of 2021, the Company sold certain non-core properties in the Kaybob and Central Alberta & Other Regions for aggregate cash proceeds of approximately $80 million and used such proceeds to reduce indebtedness under the Paramount Facility.

Subject to market conditions and availability, proceeds from new debt and/or equity financings may also provide additional sources of capital from time to time. In January 2021, as described below under "Debentures", the Company issued $35 million of senior unsecured convertible debentures and used the proceeds to reduce indebtedness under the Paramount Facility.

Paramount Facility

The Company has a $1.0 billion financial covenant-based senior secured revolving bank credit facility (the "Paramount Facility"). The maturity date of the Paramount Facility is currently November 16, 2022, which may be extended from time to time at the option of Paramount and with the agreement of the lenders.

Borrowings under the Paramount Facility bear interest at the lenders' prime lending rate, US base rate, bankers' acceptance rate, or LIBOR, as selected at the discretion of the Company, plus a margin within a graduated range (the "Pricing Range") depending on the Company's prevailing Senior Secured Debt to Consolidated EBITDA ratio. The Paramount Facility is secured by a charge over substantially all of the assets of Paramount.

Paramount is subject to the following two financial covenants under the Paramount Facility (except during the period of financial covenant relief described further below) which are tested at the end of each fiscal quarter and calculated on a trailing twelve-month basis:

- Senior Secured Debt to Consolidated EBITDA to be 3.50 to 1.00 or less; and
- Consolidated EBITDA to Consolidated Interest Expense to be 2.50 to 1.00 or greater.

Senior Secured Debt currently consists of amounts drawn on the Paramount Facility and the undrawn face amounts of letters of credit outstanding under the Paramount Facility.

Consolidated EBITDA is adjusted for material acquisitions and dispositions and is generally calculated as net income before Consolidated Interest Expense, taxes, depletion, depreciation, amortization, impairment and E&E expense and is also adjusted to exclude non-recurring items and other non-cash items including unrealized mark-to-market amounts on derivatives, unrealized foreign exchange, share-based compensation expense and accretion.

Consolidated Interest Expense is reduced by customary exclusions including interest income.

In June 2020, the Paramount Facility was amended, which amendments included:

- a period of financial covenant relief to and including June 30, 2021 (the "Covenant Relief Period") providing for a full waiver of the Senior Secured Debt to Consolidated EBITDA covenant and a reduction of the Consolidated EBITDA to Consolidated Interest Expense covenant in certain periods;

- a decrease in the size of the Paramount Facility from $1.5 billion to $1.0 billion, with availability in excess of $900 million subject to certain new additional conditions (the "New Conditions"); and

- the margin applicable to credit facility drawings remaining at the highest end of the Pricing Range during the Covenant Relief Period.

In January 2021, the Paramount Facility was further amended to remove the New Conditions on availability in excess of $900 million. As a result, the full $1.0 billion capacity of the Paramount Facility is available.

During the Covenant Relief Period, Paramount was subject to the following financial covenant, tested at the end of each fiscal quarter:

Consolidated EBITDA to Consolidated Interest Expense to be:

- 1.75 to 1.00 or greater for the quarter ending December 31, 2020, calculated on a trailing twelve-month basis; and

- 1.75 to 1.00 or greater for the quarters ending March 31, 2021 and June 30, 2021, calculated on a current quarter basis.

Paramount was in compliance with the applicable financial covenant under the Paramount Facility at December 31, 2020.

Paramount elected to exit the Covenant Relief Period in March 2021, prior to its scheduled expiry on June 30, 2021.

Paramount had undrawn letters of credit outstanding under the Paramount Facility totaling $1.3 million at December 31, 2020 that reduce the amount available to be drawn on the Paramount Facility.

Unsecured Letter of Credit Facility

The Company has a $70 million unsecured demand revolving letter of credit facility (the "LC Facility") with a Canadian bank.

Paramount's obligations under the LC Facility are supported by a performance security guarantee ("PSG") from Export Development Canada ("EDC"). The PSG is valid to June 30, 2021 and may be extended at the option of Paramount and with the agreement of EDC. At December 31, 2020, $40.7 million in undrawn letters of credit were outstanding under the LC Facility.

Debentures

In January 2021, the Company completed a private placement of $35 million of senior unsecured convertible debentures (the "Debentures"). An entity controlled by Paramount's President and Chief Executive Officer and Chairman purchased $25 million of the Debentures. An entity controlled by the

Company's Executive Vice President, Corporate Development and Planning, purchased $0.1 million of the Debentures. The Debentures mature on January 31, 2024 (the "Maturity Date"), bear interest at 7.50 percent per annum payable monthly in arrears and are convertible by the holder into Common Shares at any time prior to the Maturity Date at a conversion price of $6.72 per Common Share prior to January 31, 2022, $7.33 per Common Share on or after January 31, 2022 and prior to January 31, 2023 and $7.94 per Common Share on or after January 31, 2023.

The Debentures are redeemable by Paramount, in whole or in part, at any time prior to the Maturity Date, at a redemption price (expressed as percentages of principal amount) equal to 107.50 percent prior to January 31, 2022, 103.75 percent on or after January 31, 2022 and prior to January 31, 2023 and 101.875 percent on or after January 31, 2023.

Cash Flow Hedges

The Company had the following floating-to-fixed interest rate and electricity swaps in place at December 31, 2020:

Contract type	Aggregate notional	Remaining term	Average fixed contract rate	Reference	Fair value
Interest Rate Swaps	$250 million	January 2021 - January 2023	2.3%	CDOR (1)	(9.2)
Interest Rate Swaps	$250 million	January 2021 - January 2026	2.4%	CDOR (1)	(19.8)
Electricity Swaps	5 MWh/d (2)	January 2021 - December 2021	$51.68/MWh	AESO Pool Price (3)	0.4
					(28.6)

(1) Canadian Dollar Offered Rate.
(2) "MWh" means MegaWatt hour.
(3) Floating hourly rate established by the Alberta Electric System Operator.

In 2019, Paramount entered into interest rate swaps to manage the uncertainty of variable interest rates by fixing the underlying CDOR interest rate on a portion of the Company's long-term debt. The Company classified these arrangements as cash flow hedges and has applied hedge accounting. There is an economic relationship between the hedged items and hedging instruments as the timing and amount of the cash flows received from the interest rate swaps matched the terms of the expected highly probable forecast transactions, which is the underlying CDOR amount of interest paid on $500 million of the Company's long-term debt. A hedge ratio of 1 to 1 was established as the underlying risk of the interest rate swaps were identical to the hedged risk components. As at December 31, 2020, there were no changes to the critical terms of the hedging relationship and no hedge ineffectiveness was identified.

In the third quarter of 2020, Paramount entered into floating-to-fixed-price swaps to manage exposure to the variable market price of electricity by fixing the underlying AESO Pool Price on a portion of the Company's power. The Company classified these arrangements as cash flow hedges and has applied hedge accounting. As at December 31, 2020, there were no changes to the critical terms of the hedging relationship and no hedge ineffectiveness was identified.

Share Capital

In November 2019, Paramount issued 5.9 million Common Shares on a "flow-through" basis in respect of Canadian development expenses at a price of $6.65 per share for gross proceeds of $39.2 million pursuant to a private placement. An entity controlled by the Company's President and Chief Executive Officer and Chairman acquired 3.8 million of the Common Shares under the private placement for $24.9 million. A liability of $2.6 million was initially recognized on the issuance of the flow-through shares in respect of the

Company's obligation to renounce qualifying expenditures. Paramount has since incurred sufficient qualifying expenditures to satisfy commitments associated with the flow-through share issuance.

In January 2020, Paramount implemented a normal course issuer bid program (the "2020 NCIB") under which the Company was permitted to purchase up to 7,044,289 Common Shares for cancellation. The Company did not purchase any Common Shares under the 2020 NCIB and the 2020 NCIB expired in January 2021.

Paramount previously implemented a normal course issuer bid program in January 2019 (the "2019 NCIB"). In 2019, the Company purchased and cancelled 2,622,200 million Common Shares at a total cost of $14.4 million under the 2019 NCIB.

At February 28, 2021, Paramount had 132,642,503 Common Shares outstanding (net of 1,914,394 Common Shares held in trust under the Company's restricted share unit plan) and 9,321,415 options to acquire Common Shares outstanding, of which 2,046,890 options are exercisable.

At February 28, 2021, $35 million of Debentures are issued and outstanding. A total maximum of 5.2 million Common Shares are issuable upon conversion of the outstanding Debentures at the current conversion price of $6.72 per Common Share.

FOURTH QUARTER RESULTS

Netback (1)

Three months ended December 31	2020		2019	
		($/Boe) (2)		($/Boe) (2)
Natural gas revenue	66.7	2.83	75.1	2.73
Condensate and oil revenue	123.3	52.03	175.0	66.70
Other NGLs revenue (3)	9.5	20.61	8.5	13.03
Royalty and other revenue	2.5	–	1.3	–
Petroleum and natural gas sales	202.0	29.89	259.9	33.08
Royalties	(11.7)	(1.73)	(17.2)	(2.19)
Operating expense	(79.8)	(11.80)	(105.0)	(13.36)
Transportation and NGLs processing (4)	(24.6)	(3.63)	(22.8)	(2.90)
Netback	85.9	12.73	114.9	14.63
Financial commodity contract settlements	7.9	1.18	4.7	0.60
Netback including financial commodity contract settlements	93.8	13.91	119.6	15.23

(1) "Netback" is a Non-GAAP financial measure. See "Non-GAAP Financial Measures" in the Advisories section.
(2) Natural gas revenue shown per Mcf.
(3) Other NGLs means ethane, propane and butane.
(4) Includes downstream natural gas, NGLs and oil transportation costs and NGLs fractionation costs.

Fourth quarter 2020 petroleum and natural gas sales were $202.0 million, a decrease of $57.9 million from the fourth quarter of 2019, mainly due to lower condensate and oil prices and decreased sales volumes.

The impact of changes in sales volumes and prices on petroleum and natural gas sales are as follows:

	Natural Gas	Condensate and Oil	Other NGLs	Royalty and Other	Total
Three months ended December 31, 2019	75.1	175.0	8.5	1.3	259.9
Effect of changes in sales volumes	(10.7)	(17.0)	(2.5)	–	(30.2)
Effect of changes in prices	2.3	(34.7)	3.5	–	(28.9)
Change in royalty and other revenue	–	–	–	1.2	1.2
Three months ended December 31, 2020	**66.7**	**123.3**	**9.5**	**2.5**	**202.0**

Sales Volumes (1)

	Three months ended December 31											
	Natural Gas (MMcf/d)			Condensate and Oil (Bbl/d)			Other NGLs (Bbl/d)			Total (Boe/d)		
	2020	2019	*% Change*	**2020**	2019	*% Change*	**2020**	2019	*% Change*	**2020**	2019	*% Change*
Grande Prairie	**94.3**	93.4	*1*	**19,635**	18,851	*4*	**2,429**	2,376	*2*	**37,782**	36,789	*3*
Kaybob	**118.2**	137.4	*(14)*	**5,410**	7,771	*(30)*	**1,953**	2,504	*(22)*	**27,056**	33,167	*(18)*
Central Alberta & Other	**43.8**	68.2	*(36)*	**707**	1,894	*(63)*	**605**	2,184	*(72)*	**8,622**	15,455	*(44)*
Total	**256.3**	299.0	*(14)*	**25,752**	28,516	*(10)*	**4,987**	7,064	*(29)*	**73,460**	85,411	*(14)*

(1) Readers are referred to the Product Type Information section of this document for more information respecting the composition of sales volumes by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

Sales volumes in the fourth quarter of 2020 averaged 73,460 Boe/d compared to 85,411 Boe/d in the fourth quarter of 2019. The decrease was primarily due to the sale of the West Central Alberta Assets in December 2019 and natural declines in the Kaybob Region where the Company deployed limited capital in 2020 to focus on developments at Karr and Wapiti in the Grande Prairie Region.

These decreases were partially offset by higher sales volume in the Grande Prairie Region, where the Company brought 15 new Montney wells onstream at Karr in third and fourth quarters of 2020 and 5 new Montney wells onstream at Wapiti in the fourth quarter of 2020.

For the three months ended December 31, 2019, the West Central Alberta Assets had average sales volumes of approximately 5,900 Boe/d (20.7 MMcf/d of conventional natural gas, 2,085 Bbl/d of NGLs and 324 Bbl/d of light and medium crude oil) and a netback of approximately $5.4 million.

In the first quarter of 2021, the Company sold certain non-core properties in the Kaybob and Central Alberta CGUs for aggregate cash proceeds of approximately $80 million. For the three months ended December 31, 2020 these assets had average sales volumes of approximately 2,700 Boe/d (15.4 MMcf/d of conventional natural gas and 142 Bbl/d of NGLs) and a netback of approximately $3 million.

Commodity Prices

Three months ended December 31	2020	2019	% Change
Natural Gas			
Paramount realized price ($/Mcf)	2.83	2.73	4
AECO daily spot ($/GJ)	2.50	2.35	*6*
AECO monthly index ($/GJ)	2.62	2.21	*19*
Dawn ($/MMbtu)	2.97	2.99	*(1)*
NYMEX (US$/MMbtu)	2.76	2.42	*14*
Malin – monthly index (US$/MMbtu)	2.93	2.65	11
Condensate and Oil			
Paramount realized condensate & oil price ($/Bbl)	52.03	66.70	*(22)*
Edmonton light sweet crude oil ($/Bbl)	49.17	66.77	*(26)*
West Texas Intermediate crude oil (US$/Bbl)	42.66	56.96	*(25)*
Other NGLs (1)			
Paramount realized Other NGLs price ($/Bbl) (1)	20.61	13.03	*58*
Conway – propane ($/Bbl)	30.32	26.05	*16*
Belvieu – butane ($/Bbl)	36.10	39.85	*(9)*
Foreign Exchange			
$CDN / 1 $US	1.30	1.32	*(2)*

(1) Other NGLs means ethane, propane and butane.

The Company's realized natural gas prices increased in the fourth quarter of 2020 compared to the same period in 2019 mainly due to higher benchmark prices. Realized natural gas prices also included the impact of fixed-price AECO physical contracts to sell approximately 67,000 GJ/d of natural gas at C$2.18/GJ in the fourth quarter of 2020 (2019 - approximately 17,000 GJ/d of natural gas at C$2.36/GJ).

Realized condensate and oil prices in the fourth quarter of 2020 decreased 22 percent compared to the fourth quarter of 2019 as a result of decreases in benchmark prices.

The Company's propane and butane contracts in place in the fourth quarter of 2020 had more favorable differentials to West Texas Intermediate reference prices than the same period in 2019.

Royalties decreased $5.5 million in the fourth quarter of 2020 compared to the same period in 2019, primarily as a result of lower condensate and oil prices and decreased sales volumes.

Operating expense decreased $25.2 million to $79.8 million in the fourth quarter of 2020 compared to $105.0 million in the same period in 2019. Operating costs in the fourth quarter of 2020 were lower compared to the same period in 2019 primarily as a result of lower production in the Central and Other and Kaybob regions, cost reductions from new water disposal wells, decreased labour and power costs and supplier cost savings. Operating expenses were $11.80 per Boe in the fourth quarter of 2020, which is $0.30 per Boe higher than forecasted due to unbudgeted well workovers in Karr which increased fourth quarter production.

Transportation and NGLs processing costs increased in the fourth quarter of 2020 mainly as a result of higher contracted capacity for Karr and Wapiti, partially offset by lower production in the Central and Other and Kaybob Regions.

Net Income (Loss)

Three months ended December 31	2020	2019
Petroleum and natural gas sales	202.0	259.9
Royalties	(11.7)	(17.2)
Revenue	190.3	242.7
Loss on financial commodity contracts	(24.1)	(17.2)
	166.2	225.5
(Expenses) Income		
Operating expense	(79.8)	(105.0)
Transportation and NGLs processing	(24.6)	(22.8)
General and administrative	(9.1)	(12.6)
Share-based compensation	(6.8)	(4.2)
Depletion, depreciation and impairment reversals	268.8	(116.1)
Exploration and evaluation	(8.8)	(4.4)
Gain on sale of oil and gas assets	0.1	4.2
Interest and financing	(17.8)	(10.2)
Accretion of asset retirement obligations	(11.2)	(12.2)
Change in asset retirement obligations	(29.7)	33.8
Closure costs	–	(0.5)
Transaction and reorganization costs	–	(2.3)
Foreign exchange	(0.6)	–
	80.5	(252.3)
Other	0.4	(7.2)
Income (loss) before tax	247.1	(34.0)
Income tax recovery		
Deferred	64.4	2.9
Net income (loss)	311.5	(31.1)

Paramount recorded net income of $311.5 million for the three months ended December 31, 2020 compared to a net loss of $31.1 million in the same period in 2019. Significant factors contributing to the change are shown below:

Three months ended December 31,	
Net loss – 2019	**(31.1)**
• A recovery of $268.8 million recorded for depletion, depreciation and net impairment reversals in 2020 compared to an expense of $116.1 million in 2019, mainly due to impairment reversals of $333.7 million and lower depletion expense in 2020	384.9
• Higher income tax recovery in 2020, mainly due to the recognition of the previously unrecognized deferred income tax asset	61.5
• Expense related to changes in asset retirement obligations in 2020 compared to a recovery in 2019	(63.5)
• Lower netback in 2020, mainly due to lower condensate and oil prices and lower sales volumes, partially offset by lower operating expense	(29.0)
• Higher interest and financing expenses in 2020	(7.6)
• Higher loss on financial commodity contracts in 2020	(6.9)
• Other	3.2
Net income – 2020	311.5

Cash From Operating Activities

Cash from operating activities for the three months ended December 31, 2020 was $53.2 million compared to $70.5 million for the same period in 2019. Significant factors contributing to the change are shown below:

Three months ended December 31	
Cash from operating activities – 2019	**70.5**
• Lower netback in 2020, mainly due to lower condensate and oil prices and lower sales volumes, partially offset by lower operating expense	(29.0)
• Change in non-cash working capital	(20.5)
• Higher interest and financing expenses in 2020	(7.0)
• Lower asset retirement obligation settlements in 2020	17.9
• Closure program costs recognized in 2019	4.7
• Lower general and administrative expenses in 2020	3.5
• Higher receipts on financial commodity contract settlements in 2020	3.2
• Other	9.9
Cash from operating activities – 2020	**53.2**

Adjusted Funds Flow [(1)]

The following is a reconciliation of adjusted funds flow to the nearest GAAP measure:

Three months ended December 31	2020	2019
Cash from operating activities	**53.2**	70.5
Change in non-cash working capital	**12.5**	(8.0)
Geological and geophysical expenses	**2.1**	3.5
Asset retirement obligations settled	**0.1**	18.0
Closure costs	**–**	4.7
Dispute settlements	**–**	2.5
Transaction and reorganization costs	**–**	2.3
Adjusted funds flow	**67.9**	93.5
Adjusted funds flow ($/Boe)	**10.05**	11.89

(1) Refer to the advisories concerning Non-GAAP financial measures in the Advisories section of this document.

Adjusted funds flow in the fourth quarter of 2020 was $67.9 million compared to $93.5 million in the same period in 2019. Significant factors contributing to the change are shown below:

Three months ended December 31	
Adjusted funds flow – 2019	**93.5**
• Lower netback in 2020, mainly due to lower condensate and oil prices and lower sales volumes, partially offset by lower operating expense	(29.0)
• Higher interest and financing expenses in 2020	(7.0)
• Lower general and administrative expenses in 2020	3.5
• Higher receipts on financial commodity contract settlements in 2020	3.2
• Other	3.7
Adjusted funds flow – 2020	**67.9**

Total Capital Expenditures by Region (1)

Three months ended December 31	2020	2019
Grande Prairie Region	**64.3**	60.7
Kaybob Region	**1.8**	9.5
Central Alberta and Other Region	**0.8**	0.6
Corporate (2)	**(1.8)**	–
Land and property acquisitions	**–**	1.4
Total capital expenditures	**65.1**	72.2

(1) Readers are referred to the advisories concerning Non-GAAP financial measures in the Advisories section of this document.
(2) Includes transfers between regions.

Total capital expenditures in the fourth quarter of 2020 totaled $65.1 million, with the majority of spending directed towards drilling and completion programs in the Grande Prairie Region.

QUARTERLY INFORMATION

	2020				2019			
	Q4	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**202.0**	138.8	113.2	172.1	259.9	199.8	209.2	246.1
Net income (loss)	**311.5**	(23.3)	(75.7)	(235.1)	(31.1)	141.0	(121.0)	(76.7)
Per share – basic & diluted ($/share)	***2.35***	*(0.17)*	*(0.57)*	*(1.76)*	*(0.24)*	*1.08*	*(0.93)*	*(0.59)*
Cash from (used in) operating activities	**53.2**	11.4	(14.2)	30.5	70.5	48.6	48.1	88.5
Per share – basic & diluted ($/share)	***0.40***	*0.09*	*(0.11)*	*0.23*	*0.54*	*0.37*	*0.37*	*0.68*
Adjusted funds flow	**67.9**	29.5	19.0	33.5	93.5	50.9	54.2	100.5
Per share – basic & diluted ($/share)	***0.51***	*0.22*	*0.14*	*0.25*	*0.71*	*0.39*	*0.41*	*0.77*
Sales volumes (1)								
Natural gas (MMcf/d)	**256.3**	224.0	253.2	261.5	299.0	296.6	309.7	308.0
Condensate and oil (Bbl/d)	**25,752**	19,782	22,823	21,898	28,516	24,761	23,312	23,679
Other NGLs (Bbl/d)	**4,987**	3,952	3,817	4,539	7,064	6,851	6,859	6,284
Total (Boe/d)	**73,460**	61,064	68,839	70,022	85,411	81,046	81,793	81,296
Realized prices								
Natural gas ($/Mcf)	**2.83**	1.94	1.94	2.25	2.73	1.58	1.76	3.37
Condensate and oil ($/Bbl)	**52.03**	48.74	29.05	55.92	66.70	65.73	71.02	63.26
Other NGLs ($/Bbl)	**20.61**	18.10	12.28	10.75	13.03	9.78	11.01	28.55
Total ($/Boe)	**29.89**	24.70	18.07	27.01	33.08	26.80	28.10	33.63

(1) Readers are referred to the Product Type Information section of this document for more information respecting the composition of sales volumes by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil.

Significant Items Impacting Quarterly Results

Quarterly earnings variances include the impacts of changing production volumes and market prices.

- Fourth quarter 2020 earnings include aggregate impairment reversals of $333.7 million from previously recorded impairment charges of petroleum and natural gas assets and a deferred income tax recovery of $64.4 million, partially offset by a charge of $29.7 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- The third quarter 2020 loss includes a recovery of $25.6 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- The second quarter 2020 loss includes a recovery of $13.6 million related to deferred income tax.
- The first quarter 2020 loss includes a $191.8 million impairment of petroleum and natural gas assets and a derecognition of $130.0 million of the deferred income tax asset, partially offset by a recovery of $94.8 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- The fourth quarter 2019 loss includes a recovery of $33.8 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- Third quarter 2019 earnings include a $157.3 million gain on the sale of oil and gas assets, primarily related to the Midstream Transaction and a recovery of $73.5 million related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value.
- The second quarter 2019 loss includes $102.1 million of deferred income tax expense, primarily related to a reduction in Alberta income tax rates and a $27.6 million gain on financial commodity contracts.
- The first quarter 2019 loss includes a $72.6 million loss on financial commodity contracts.

OTHER INFORMATION

Contractual Obligations

Paramount had the following contractual obligations at December 31, 2020:(1)

	Within 1 year	After one year but not more than three years	After three years but not more than five years	More than five years	Total
Paramount Facility	–	815.7	–	–	**815.7**
Transportation and processing commitments (2)	259.1	467.8	421.7	1,174.4	**2,323.0**
Asset retirement obligations (3)	22.3	74.6	87.7	1,167.1	**1,351.7**
Finance lease and other commitments (4)	12.9	13.6	14.1	–	**40.6**
	294.3	**1,371.7**	**523.5**	**2,341.5**	**4,531.0**

(1) Excludes risk management liabilities and accounts payable and accrued liabilities, which are described in Note 14 of the Consolidated Financial Statements.
(2) Certain of the transportation and processing commitments are secured by outstanding letters of credit totaling $13.2 million at December 31, 2020 (December 31, 2019 - $10.2 million).
(3) Undiscounted, uninflated asset retirement obligations estimated as at December 31, 2020. Does not include impact of government funding. Estimated costs and timing of settlement are revised from time-to-time based on new information.
(4) Undiscounted finance lease payments in respect of office and vehicle commitments have been reduced by sublease revenue amounts receivable.

Transportation and processing commitments mainly relate to long-term firm service arrangements for the processing and transportation of the Company's sales volumes.

Contingencies

In the normal course of Paramount's operations, the Company may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty. Other than with respect to the Dissent Payment Entitlement, Paramount does not anticipate that these claims will have a material impact on its financial position.

Tax and royalty legislation and regulations, and government interpretation and administration thereof, continually change. As a result, there are often tax and royalty matters under review by relevant government authorities. All tax and royalty filings are subject to subsequent government audit and potential reassessments. Accordingly, the final amounts may differ materially from amounts estimated and recorded.

Provision

In the first quarter of 2020, a provision of $4.7 million was recorded related to a pending partner dispute.

NEW AND UPDATED ACCOUNTING POLICIES AND STANDARDS

Financial Instruments

Effective January 1, 2020, the Company adopted the amendments to IFRS 9 – *Financial Instruments* ("IFRS 9"), IAS 39 – *Financial Instruments: Recognition and Measurement* ("IAS 39") and IFRS 7 – *Financial Instruments: Disclosures* ("IFRS 7"). These amendments provided relief on hedge accounting from the potential effects of the uncertainty arising from the phase-out of interest rate benchmarks, the Interbank Offered Rate ("IBOR") reform. The Company's floating-to-fixed interest rate swaps, which are described in Note 14 of the Consolidated Financial Statements, are impacted by these amendments as hedge accounting is applied to these instruments and hedging relationships may be impacted by the IBOR reform. There has been no impact on the recognized assets, liabilities or comprehensive loss of the Company resulting from the adoption of these amendments.

Government Grants

Government grants are recognized when there is reasonable assurance that the relevant conditions of the grant are met and that the grant will be received. The Company records the grant in the Consolidated Financial Statements with the related expenditure in the period in which the eligible costs are incurred. For the year ended December 31, 2020 the Company recognized $11.1 million relating to the CEWS program which reduced general and administrative expenses, operating expenses and capital expenditures by $6.4 million, $4.0 million and $0.7 million, respectively. Asset retirement settlements approved under government programs are recorded as a credit to earnings in change in asset retirement obligations in the period in which the related eligible costs are incurred.

Future Changes in Accounting Standards

In 2020, the International Accounting Standards Board published phase two of its amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 – *Insurance Contracts* and IFRS 16 - *Leases* ("IFRS 16") to assist companies in applying IFRS when changes are made to contractual cash flows or hedging relationships arising from the replacement of an interest rate benchmark with an alternative benchmark rate from IBOR reform. These amendments are effective for years beginning on or after January 1, 2021. Paramount expects that the amendments will not have a material impact on the Consolidated Financial Statements on adoption.

DISCLOSURE CONTROLS AND PROCEDURES

As of the year ended December 31, 2020, an evaluation of the effectiveness of Paramount's disclosure controls and procedures ("DCP"), as defined under National Instrument 52-109 "*Certification of Disclosure in Issuers' Annual and Interim Filings*" ("NI 52-109"), was performed by the Company's Management with the oversight of the Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's DCP are effective as of December 31, 2020.

It should be noted that while the Company's Chief Executive Officer and Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Company's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Management, with the oversight of the Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the Company's internal controls over financial reporting ("ICFR") as defined under NI 52-109 as at December 31, 2020. In making its evaluation, Management used the Committee of Sponsoring Organizations of the Treadway Commission Framework in Internal Control – Integrated Framework (2013). Based on this evaluation, the Company's Chief Executive Officer and Chief Financial Officer have concluded that the Company's ICFR was effective as of December 31, 2020.

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 policies or procedures may deteriorate.

Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2020, there was no change in the Company's ICFR that materially affected, or is reasonably likely to materially affect, the Company's ICFR. Paramount does not believe that process changes adopted in connection with the COVID-19 pandemic have materially affected ICFR.

RISK FACTORS

Readers should, in conjunction with their review of this MD&A, carefully review the "Risk Factors" section in the Company's Annual Information Form for the year ended December 31, 2020, which is available under the Company's profile on SEDAR at www.sedar.com.

The course of the COVID-19 pandemic and its ultimate economic impact remain highly uncertain. The ultimate impact of the pandemic on Paramount's future operations and financial performance is unknown and will be dependent on a number of unpredictable factors outside of the knowledge and control of Management, including: (i) the duration and severity of the pandemic; (ii) the impact of the pandemic on economic growth, commodity prices and financial and capital markets; and (iii) governmental responses and restrictions. These uncertainties may continue to persist beyond the point where the outbreak of the COVID-19 virus has subsided. See "Risk Factors – COVID 19 Pandemic" in the Annual Information Form.

CRITICAL ACCOUNTING ESTIMATES

The timely preparation of financial statements requires Management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosures regarding contingent assets and liabilities. Estimates and assumptions are regularly evaluated and are based on Management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Changes in judgments, estimates and assumptions based on new information could result in a material change to the carrying amount of assets or liabilities and have a material impact on assets, liabilities, revenues and expenses recognized in future periods.

The potential impact of the COVID-19 pandemic has been considered by Management in making judgments, estimates and assumptions used in the preparation of the Consolidated Financial Statements, but the inherent risks and uncertainties resulting from the pandemic may result in material changes to such judgments, estimates and assumptions in future periods as additional information becomes available.

A description of the accounting judgments, estimates and assumptions that are considered significant is set out below.

Exploration or Development

The Company is required to apply judgment when designating a project as exploration and evaluation or development, including assessments of geological and technical characteristics and other factors related to each project.

Exploration and Evaluation Projects

The accounting for E&E projects requires Management to make judgments as to whether exploratory projects have discovered economically recoverable quantities of petroleum and natural gas, which requires the quantity and realizable value of such petroleum and natural gas to be estimated. Previous estimates are sometimes revised as new information becomes available. Where it is determined that an exploratory project did not discover economically recoverable petroleum and natural gas, the costs are written-off as E&E expense.

If hydrocarbons are encountered, but further appraisal activity is required, the exploratory costs remain capitalized as long as sufficient progress is being made in assessing whether the recovery of the petroleum and natural gas is economically viable. The concept of "sufficient progress" is a judgmental area, and it is possible to have exploratory costs remain capitalized for several years while additional exploratory activities are carried out or the Company seeks government, regulatory or partner approval for development plans. E&E assets are subject to ongoing technical, commercial and Management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery. When Management is making this assessment, changes to project economics, expected quantities of petroleum and natural gas, expected production techniques, drilling results, estimated capital expenditures and production costs, results of other operators in the region and access to infrastructure and potential infrastructure expansions are important factors. Where it is determined that an exploratory project is not economically viable, the costs are written-off as E&E expense.

Reserves Estimates

Reserves engineering is an inherently complex and subjective process of estimating underground accumulations of petroleum and natural gas. The process relies on judgments based on the interpretation of available geological, geophysical, engineering and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of such data, the accuracy of various economic assumptions and the judgment of those preparing the estimate. Because these estimates depend on many assumptions, all of which may differ from actual results, reserves estimates, and estimates of future net revenue will be different from the sales volumes ultimately recovered and net revenues actually realized. Changes in market conditions, regulatory matters, the results of subsequent drilling, testing and production and other factors may result in revisions to the original estimates.

Estimates of reserves impact: (i) the assessment of whether a new well has found economically recoverable reserves; (ii) depletion rates; (iii) the estimated fair value of petroleum and natural gas properties acquired in a business combination; and (iv) the estimated recoverable amount of petroleum and natural gas properties used for the purposes of impairment and impairment reversal assessments, all of which could have a material impact on earnings.

Business Combinations

Management is required to exercise judgment in determining whether assets acquired and liabilities assumed constitute a business. A business consists of an integrated set of assets and activities, comprised of inputs and processes, that is capable of being conducted and managed as a business by a market participant.

Business combinations are accounted for using the acquisition method of accounting, whereby the net identifiable assets acquired are recorded at fair value. The fair value of individual assets is often required to be estimated, which may involve estimating the fair values of proved plus probable reserves, contingent resources, tangible assets, undeveloped land, intangible assets and other assets. These estimates incorporate assumptions using indicators of fair value, as determined by Management. Changes in any of the estimates or assumptions used in determining the fair value of the net identifiable assets acquired may impact the carrying values assigned to assets acquired and liabilities assumed and could have a material impact on earnings.

Estimates of Recoverable Amounts

Estimates of recoverable amounts used in impairment and impairment reversal assessments often incorporate level three fair value hierarchy inputs, including estimated volumes and future net revenues from proved plus probable reserves, contingent resource estimates, future net cash flow estimates related to other long-lived assets and internal and external market metrics used to estimate value based on comparable assets and transactions. By their nature, such estimates are subject to measurement uncertainty. Changes in such estimates, and differences between actual and estimated amounts, could have a material impact on earnings.

Determination of CGUs

The recoverability of the carrying value of petroleum and natural gas assets is generally assessed at the CGU level. The determination of the properties and other assets grouped within a particular CGU is based on Management’s judgment with respect to the integration between assets, shared infrastructure and cash flows, the overall significance of individual properties and the manner in which Management monitors its operations and allocates capital. Changes in the assets comprising CGUs could have an impact on estimated recoverable amounts used in impairment assessments and could have a material impact on earnings.

Depletion

Depletion rates are determined based on Management's estimates of the expected usage pattern of the Company's petroleum and natural gas assets, including assumptions regarding future production volumes and the useful lives of production equipment and gathering systems.

Dissent Payment Entitlement

The Dissent Payment Entitlement is a financial instrument measured at amortized cost and was recorded based on the estimated fair value thereof on initial recognition. Management exercised judgment in estimating the fair value of the Dissent Payment Entitlement through the use of available market inputs and other assumptions. On initial recognition and at the end of each period Management assess the Dissent Payment Entitlement for any expected credit loss. Changes in estimates of the initial fair value and the expected credit loss could have a material impact on the Dissent Payment Entitlement asset and on comprehensive income.

Investments in Securities

The Company's investments in securities are accounted for as fair value through OCI financial assets. Management is required to exercise judgment in estimating the fair value of investments in the securities of corporations that are not publicly traded using the Company's assessment of available market inputs and other assumptions. Changes in estimates of fair value for such investments could have a material impact on comprehensive income.

Provisions

A provision is recognized where the Company has determined that it has a present obligation arising from past events and the settlement of the obligation is expected to result in an outflow of economic benefits. The determination of whether the Company has a present obligation arising from past events requires Management to exercise judgement as to the facts and circumstances of the event and the extent of any expected obligations of Paramount. Changes in facts and circumstances as a result of new information and other developments may impact Management's assessment of the Company's obligations, if any, in respect of such events. Changes in such estimates could have a material impact on Paramount's assets, liabilities, revenues, expenses and earnings.

Asset Retirement Obligations

Estimates of asset retirement costs are based on assumptions regarding the methods, timing, economic environment and regulatory standards that are expected to exist at the time assets are retired. Management also exercises judgment to determine the credit-adjusted risk-free discount rate at the end of each reporting period which may change in response to numerous market factors. The Company adjusts estimated amounts periodically as assumptions are updated to incorporate new information. The actual amount and timing of payments to settle the obligations may differ materially from estimates.

Share-Based Payments

The Company estimates the grant date value of stock options awarded using the Black-Scholes-Merton model. The inputs used to determine the estimated value of the options are based on assumptions regarding share price volatility, the expected life of the options, expected forfeiture rates and future interest rates. By their nature, these inputs are subject to measurement uncertainty and require Management to exercise judgment.

Income Taxes

Accounting for income taxes is a complex process requiring Management to interpret frequently changing laws and regulations and make judgments and estimates related to the application of tax law, the timing of temporary difference reversals and the likelihood of realizing deferred income tax assets. All tax filings are subject to subsequent government audits and potential reassessment. These interpretations and judgments, and changes related to them, impact current and deferred income tax provisions, the carrying value of deferred income tax assets and liabilities and could have a material impact on earnings.

PRODUCT TYPE INFORMATION

This MD&A includes references to sales volumes of "natural gas", "condensate and oil" and "Other NGLs" and revenues therefrom. "Natural gas" refers to conventional natural gas and shale gas combined. "Condensate and oil" refers to condensate, light and medium crude oil and tight oil combined. "Other NGLs" refers to ethane, propane and butane. Below is a complete breakdown of sales volumes for applicable periods by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil. Numbers may not add due to rounding.

	2020				2019				Annual		
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	2020	2019	2018
SALES VOLUMES - BY PRODUCT TYPE											
Shale gas (MMcf/d)	170.7	141.0	156.0	158.9	176.6	159.3	164.1	163.9	156.7	166.0	165.9
Conventional natural gas (MMcf/d)	85.6	83.0	97.2	102.6	122.4	137.3	145.6	144.1	92.0	137.3	160.0
Natural gas (MMcf/d)	256.3	224.0	253.2	261.5	299.0	296.6	309.7	308.0	248.7	303.3	325.9
Condensate (Bbl/d)	22,782	17,020	19,615	17,908	23,956	20,230	17,781	16,933	19,334	19,746	16,384
Other NGLs (Bbl/d)	4,987	3,952	3,817	4,539	7,064	6,851	6,859	6,284	4,325	6,767	7,386
NGLs (Bbl/d)	27,769	20,972	23,432	22,447	31,020	27,081	24,640	23,217	23,659	26,513	23,770
Tight oil (Bbl/d)	437	457	381	575	745	523	603	653	462	631	830
Light and Medium crude oil (Bbl/d)	2,533	2,305	2,827	3,416	3,815	4,008	4,928	6,093	2,768	4,703	7,024
Crude oil (Bbl/d)	2,970	2,762	3,208	3,991	4,560	4,531	5,531	6,746	3,230	5,334	7,854
Total (Boe/d)	73,460	61,064	68,839	70,022	85,411	81,046	81,793	81,296	68,340	82,394	85,941

	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019	Q3 2019	Q2 2019	Q1 2019	2020	2019	2018
SALES VOLUMES – BY REGION BY PRODUCT TYPE											
GRANDE PRAIRIE REGION											
Shale gas (MMcf/d)	92.7	66.0	76.8	73.1	91.5	70.5	73.4	76.7	77.2	78.0	65.5
Conventional natural gas (MMcf/d)	1.6	1.3	1.5	1.5	1.9	1.6	1.2	1.3	1.4	1.5	10.7
Natural gas (MMcf/d)	94.3	67.3	78.3	74.6	93.4	72.1	74.6	78.0	78.6	79.5	76.2
Condensate (Bbl/d)	19,635	13,959	16,292	14,058	18,760	14,269	11,678	10,883	15,991	13,920	11,342
Other NGLs (Bbl/d)	2,429	2,060	1,680	1,680	2,376	1,587	1,686	1,602	1,964	1,814	1,945
NGLs (Bbl/d)	22,064	16,019	17,972	15,738	21,136	15,856	13,364	12,485	17,955	15,734	13,287
Tight oil (Bbl/d)	–	–	–	–	–	–	–	–	–	–	–
Light and medium crude oil (Bbl/d)	–	1	17	39	91	61	13	46	14	53	77
Crude oil (Bbl/d)	–	1	17	39	91	61	13	46	14	53	77
Total (Boe/d)	37,782	27,237	31,039	28,214	36,789	27,927	25,804	25,530	31,076	29,040	26,059

	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019	Q3 2019	Q2 2019	Q1 2019	2020	2019	2018
KAYBOB REGION											
Shale gas (MMcf/d)	41.9	40.4	44.4	48.6	48.3	52.4	51.6	49.1	43.8	50.3	59.4
Conventional natural gas (MMcf/d)	76.3	73.4	87.1	91.6	89.1	91.8	101.5	101.4	82.1	95.9	102.8
Natural gas (MMcf/d)	118.2	113.8	131.5	140.2	137.4	144.2	153.1	150.5	125.9	146.2	162.2
Condensate (Bbl/d)	2,631	2,577	2,954	3,385	3,899	4,411	4,526	4,618	2,885	4,361	3,519
Other NGLs (Bbl/d)	1,953	1,363	1,718	2,218	2,504	2,450	2,622	2,324	1,812	2,476	2,450
NGLs (Bbl/d)	4,584	3,940	4,672	5,603	6,403	6,861	7,148	6,942	4,697	6,837	5,969
Tight oil (Bbl/d)	299	308	203	394	541	329	286	280	301	360	439
Light and medium crude oil (Bbl/d)	2,480	2,257	2,762	3,343	3,331	3,391	4,182	4,835	2,709	3,929	5,565
Crude oil (Bbl/d)	2,779	2,565	2,965	3,737	3,872	3,720	4,468	5,115	3,010	4,289	6,004
Total (Boe/d)	27,056	25,477	29,561	32,700	33,167	34,615	37,127	37,143	28,685	35,500	39,004

	2020				2019				Annual		
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1	2020	2019	2018
CENTRAL ALBERTA & OTHER REGION											
Shale gas (MMcf/d)	**36.1**	34.6	34.8	37.1	36.8	36.4	39.1	38.1	**35.7**	37.7	41.0
Conventional natural gas (MMcf/d)	**7.7**	8.3	8.6	9.6	31.4	43.9	42.9	41.4	**8.5**	39.9	46.5
Natural gas (MMcf/d)	**43.8**	42.9	43.4	46.7	68.2	80.3	82.0	79.5	**44.2**	77.6	87.5
Condensate (Bbl/d)	**515**	484	369	465	1,298	1,551	1,577	1,433	**458**	1,464	1,522
Other NGLs (Bbl/d)	**605**	529	419	641	2,184	2,814	2,551	2,358	**549**	2,477	2,991
NGLs (Bbl/d)	**1,120**	1,013	788	1,106	3,482	4,365	4,128	3,791	**1,007**	3,941	4,513
Tight oil (Bbl/d)	**138**	149	178	180	203	194	317	373	**161**	271	391
Light and Medium crude oil (Bbl/d)	**54**	47	48	33	393	556	733	1,211	**46**	721	1,383
Crude oil (Bbl/d)	**192**	196	226	213	596	750	1,050	1,584	**207**	992	1,774
Total (Boe/d)	**8,622**	8,350	8,239	9,108	15,455	18,504	18,862	18,623	**8,579**	17,854	20,878

The Company forecasts that 2021 sales volumes will average between 77,000 Boe/d and 80,000 Boe/d (55% shale gas and conventional natural gas combined, 39% light and medium crude oil, tight oil and condensate combined and 6% other NGLs). First half 2021 sales volumes are expected to average between 74,000 Boe/d and 76,000 Boe/d (57% shale gas and conventional natural gas combined, 37% light and medium crude oil, tight oil and condensate combined and 6% other NGLs). Second half 2021 sales volumes are expected to increase to average between 80,000 Boe/d and 84,000 Boe/d (54% shale gas and conventional natural gas combined, 40% light and medium crude oil, tight oil and condensate combined and 6% other NGLs).

ADVISORIES

Forward-looking Information

Certain statements in this MD&A constitute forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as "anticipate", "believe", "estimate", "will", "expect", "plan", "schedule", "intend", "propose", or similar words suggesting future outcomes or an outlook. Forward-looking information in this document includes, but is not limited to:

- planned capital expenditures in 2021 and the timing and allocation thereof;
- forecast sales volumes for 2021 and certain periods therein;
- forecast free cash flow in 2021;
- planned exploration, development and production activities, including the expected timing of completing and bringing new wells on production;
- planned facility outages and turnarounds;
- planned abandonment and reclamation expenditures and activities in 2021 and anticipated funding under the ASRP;
- the expectation that the Company will be able to fund budgeted capital expenditures and budgeted expenditures for abandonment and reclamation activities from cash from operating activities;
- the anticipation that legal proceedings will not have a material impact on Paramount's financial position;
- the expectation that the adoption of the amendments to IFRS described under "Updates to Accounting Policies - Future Changes in Accounting Standards" will not have a material impact on the Company's Consolidated Financial Statements; and
- COVID-19 pandemic response measures and the potential impacts of the pandemic.

Such forward-looking information is based on a number of assumptions which may prove to be incorrect. Assumptions have been made with respect to the following matters, in addition to any other assumptions identified in this document:

- future commodity prices and the potential impact of the COVID-19 pandemic thereon;
- the likely impact of the COVID-19 pandemic on operations;
- royalty rates, taxes and capital, operating, general & administrative and other costs;
- foreign currency exchange rates and interest rates;
- general business, economic and market conditions;
- the ability of Paramount to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of Paramount to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost to carry out its activities;
- the ability of Paramount to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms;
- the ability of Paramount to market its production successfully to current and new customers;
- the ability of Paramount and its industry partners to obtain drilling success (including in respect of anticipated production volumes, reserves additions, product yields and resource recoveries) and operational improvements, efficiencies and results consistent with expectations;
- the timely receipt of required governmental and regulatory approvals;
- the application of regulatory requirements respecting abandonment and reclamation;
- the merits of outstanding and pending legal proceedings; and

- anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins and the construction, commissioning and start-up of new and expanded facilities).

Although Paramount believes that the expectations reflected in such forward-looking information are reasonable based on the information available at the time of this MD&A, undue reliance should not be placed on the forward-looking information as Paramount can give no assurance that such expectations will prove to be correct. Forward-looking information is based on expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Paramount and described in the forward-looking information. The material risks and uncertainties include, but are not limited to:

- those risks set out in this MD&A under "Risk Factors";
- fluctuations in commodity prices, including in relation to the impact of the COVID-19 pandemic;
- changes in capital spending plans and planned exploration and development activities;
- changes in foreign currency exchange rates and interest rates;
- the uncertainty of estimates and projections relating to future revenue, free cash flow, future production, reserves additions, product yields (including condensate to natural gas ratios), resource recoveries, royalty rates, taxes and costs and expenses;
- the ability to secure adequate product processing, transportation, fractionation, and storage capacity on acceptable terms;
- operational risks in exploring for, developing, producing and transporting sakes volumes, including the risk of spills, leaks or blowouts;
- the ability to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost;
- potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities);
- processing, pipeline and fractionation infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves estimates;
- general business, economic and market conditions;
- the ability to generate sufficient adjusted funds flow and obtain financing to fund planned exploration, development and operational activities and meet current and future commitments and obligations (including product processing, transportation, fractionation and similar commitments and obligations);
- changes in, or in the interpretation of, laws, regulations or policies (including environmental laws);
- the ability to obtain required governmental or regulatory approvals in a timely manner, and to enter into and maintain leases and licenses;
- the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access;
- the timing and cost of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination;
- uncertainties regarding aboriginal claims and in maintaining relationships with local populations and other stakeholders;
- the outcome of existing and potential lawsuits, regulatory actions, audits and assessments; and
- other risks and uncertainties described elsewhere in this document and in Paramount's other filings with Canadian securities authorities.

The foregoing list of risks is not exhaustive. For more information relating to risks, see the section titled "Risk Factors" in Paramount's annual information form for the year ended December 31, 2020, which is available on SEDAR at www.sedar.com. The forward-looking information contained in this document is made as of the date hereof and, except as required by applicable securities law, Paramount undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Non-GAAP Financial Measures

In this document, "Adjusted funds flow", "Free cash flow", "Netback", "Net debt", "Adjusted working capital" and "Total capital expenditures", collectively the "Non-GAAP Financial Measures", are used and do not have any standardized meanings as prescribed by IFRS.

"Adjusted funds flow" refers to cash from (used in) operating activities before net changes in non-cash working capital, geological and geophysical expenses, asset retirement obligation settlements, closure costs, provision and other, dispute settlements and transaction and reorganization costs. Adjusted funds flow is used to assist Management and investors in measuring the Company's ability to fund capital programs and meet financial obligations, including the settlement of asset retirement obligations. Asset retirement obligation settlements are excluded from the calculation of adjusted funds flow because such expenditures are not directly linked to the revenue generating activities of the Company. Paramount manages the timing of expenditures related to asset retirement obligation settlements in accordance with regulatory requirements and its overall approach to managing its asset retirement obligations and, as a result, amounts incurred may vary significantly from period to period. Adjusted funds flow is not intended to represent cash from operating activities, net loss or any other GAAP measure and should not be construed as being an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS. Refer to the Consolidated Results section of this MD&A for the calculation thereof.

"Free cash flow" refers to adjusted funds flow less total capital expenditures and asset retirement obligation settlements. Free cash flow is used by Management and investors to assess the amount of internally generated cash available to repay debt, reinvest in the business or return to shareholders.

"Netback" equals petroleum and natural gas sales less royalties, operating expense and transportation and NGLs processing costs. Netback is commonly used by Management and investors to compare the results of the Company's oil and gas operations between periods. Refer to the Operating Results section of this MD&A for the calculation thereof.

"Net debt" is a measure of the Company's overall debt position after adjusting for certain working capital and other amounts and is used by Management to assess the Company's overall leverage position. Refer to the Liquidity and Capital Resources section of this MD&A for the calculation of "Net debt" and "Adjusted working capital".

"Total capital expenditures" refers to the Company's property, plant and equipment and exploration expenditures. Refer to the Property, Plant and Equipment and Exploration Expenditures section of this MD&A for the calculation thereof.

The Non-GAAP Financial Measures should not be considered in isolation or construed as alternatives to their most directly comparable measure calculated in accordance with GAAP, or other measures of financial performance calculated in accordance with GAAP. The Non-GAAP Financial Measures are unlikely to be comparable to similar measures presented by other issuers.

Oil and Gas Measures and Definitions

The term "liquids" includes oil, condensate and Other NGLs (ethane, propane and butane). NGLs consist of condensate and Other NGLs.

Abbreviations

Liquids	
Bbl	Barrels
Bbl/d	Barrels per day
NGLs	Natural gas liquids
Condensate	Pentane and heavier hydrocarbons

Oil Equivalent	
Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day

Natural Gas	
Mcf	Thousands of cubic feet
MMcf/d	Millions of cubic feet per day
GJ	Gigajoule
GJ/d	Gigajoule per day
MMbtu	Millions of British thermal units
MMbtu/d	Millions of British thermal units per day
WTI	NYMEX
AECO	AECO-C reference price

This MD&A contains disclosures expressed as "Boe", "$/Boe" and "Boe/d". Natural gas equivalency volumes have been derived using the ratio of six thousand cubic feet of natural gas to one barrel of oil when converting natural gas to Boe. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. For the year ended December 31, 2020, the value ratio between crude oil and natural gas was approximately 21:1. This value ratio is significantly different from the energy equivalency ratio of 6:1. Using a 6:1 ratio would be misleading as an indication of value.

Additional information respecting the Company's oil and gas properties and operations is provided in the Company's annual information form for the year ended December 31, 2020 which is available on SEDAR at www.sedar.com.

Consolidated Financial Statements
As at December 31, 2020 and 2019 and for the years then ended

MANAGEMENT’S REPORT

The accompanying Consolidated Financial Statements of Paramount Resources Ltd. (the "Company") are the responsibility of Management and have been approved by the Company’s Board of Directors. The Consolidated Financial Statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect Management’s best judgments. If alternate accounting methods exist, Management has chosen those policies it considers the most appropriate in the circumstances. Financial information included in the Company’s annual report, including Management’s Discussion and Analysis, is consistent with these Consolidated Financial Statements.

Management is also responsible for establishing and maintaining adequate internal control over the Company’s financial reporting. The Company’s internal control system was designed to provide reasonable assurance that all transactions are recorded that are necessary for the preparation and presentation of financial statements in accordance with International Financial Reporting Standards, that such transactions are recorded accurately and that the Company’s assets are safeguarded.

The Board of Directors is responsible for ensuring that Management fulfills its responsibilities for financial reporting and internal control. The Board of Directors fulfills this responsibility through the Audit Committee, which is comprised entirely of non-Management directors. The Audit Committee meets regularly with Management and the independent auditors to ensure that Management’s responsibilities are properly discharged and to review the Consolidated Financial Statements. The Audit Committee reports its findings to the Board of Directors for consideration when approving the annual Consolidated Financial Statements for issuance. The Audit Committee also considers, for review by the Board of Directors and approval by the shareholders, the engagement or re-appointment of the independent auditors.

Ernst & Young LLP, independent auditors appointed by the shareholders of the Company, conducts an examination of the Consolidated Financial Statements in accordance with Canadian Generally Accepted Auditing Standards. Ernst & Young LLP has full and free access to the Board of Directors, the Audit Committee and Management.

/s/ J.H.T. Riddell
J.H.T. Riddell
President and Chief Executive Officer and Chairman

/s/ P.R. Kinvig
P.R. Kinvig
Chief Financial Officer

March 2, 2021

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Paramount Resources Ltd.

Opinion

We have audited the consolidated financial statements of Paramount Resources Ltd. and its subsidiaries (collectively, the Company), which comprise the consolidated balance sheets as at December 31, 2020 and 2019, and the consolidated statements of comprehensive loss, consolidated statements of cash flows and consolidated statements of shareholders' equity for the years ended December 31, 2020 and 2019, and notes to the consolidated financial statements, including a summary of significant accounting policies.

In our opinion, the accompanying consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2020 and 2019, and its consolidated financial performance and its consolidated cash flows for the years ended December 31, 2020 and 2019 in accordance with International Financial Reporting Standards (IFRSs).

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 *Auditor's Responsibilities for the Audit of the Consolidated Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated 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.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in the audit of the consolidated financial statements of the current period. These matters were addressed in the context of the audit of the consolidated financial statements as a whole, and in forming the auditor's opinion thereon, and we do not provide a separate opinion on these matters. For each matter below, our description of how our audit addressed the matter is provided in that context.

We have fulfilled the responsibilities described in the *Auditor's responsibilities for the audit of the consolidated financial statements* section of our report, including in relation to these matters. Accordingly, our audit included the performance of procedures designed to respond to our assessment of the risks of material misstatement of the consolidated financial statements. The results of our audit procedures, including the procedures performed to address the matters below, provide the basis for our audit opinion on the accompanying consolidated financial statements.

Impairment and impairment reversal of property, plant and equipment.

As at December 31, 2020, the carrying value of property, plant and equipment (PP&E) was $1,960 million. For the year ended December 31, 2020, a net impairment reversal of $142 million was recorded with respect to PP&E. Refer to Note 1 for a description of the Company's impairment of non-financial assets accounting policy. Refer to Note 5 for the Company's PP&E impairment and impairment reversal disclosures. PP&E is tested for impairment or impairment reversal only when circumstances indicate that the carrying value of a cash generating unit

To test the Company's estimated recoverable amount, we performed the following procedures, among others:

- Evaluated management's experts' competence, capability and objectivity as well as obtained an understanding of the work they performed. The appropriateness of their work as audit evidence was evaluated by considering the relevance and reasonableness of the methods and inputs utilized

(CGU) differs from the recoverable amount. Impairment or impairment reversal is determined by estimating a CGU's respective recoverable amount. The recoverable amount of the CGUs was based on expected after-tax future net cash flows from the production of proved and probable reserve volumes using forecast commodity prices and costs, discounted using market-based rates. Proved and probable reserves were determined by the Company's independent petroleum engineers (management's experts).

Auditing the Company's estimated recoverable amount was complex due to the subjective nature of the various management inputs and assumptions and the significant effect changes in these could have on the recoverable amount. Additionally, the evaluation of this estimate required specialized skills and knowledge. The primary inputs noted in the fair value less cost of disposal model were the discount rate and after-tax future net cash flows from the production of proved plus probable reserve volumes.

- Involved our internal valuation specialists to assess the methodology applied and the various inputs utilized in determining the discount rate by referencing current industry, economic, and comparable company information, as well as company and cash-flow specific risk premiums
- With the assistance of our internal valuation specialists, we also assessed the market capitalization deficiency and observed quantitative and qualitative reconciliations using market data and subsequent transactions, to refute the deficiency as contrary information
- Compared forecast benchmark commodity price estimates of oil, natural gas, and NGLs against historically realized prices and to other third-party price forecasts
- Assessed forecasted production, royalty, operating cost, and capital cost data by comparing it to historical performance of the Company
- Evaluated the adequacy of the impairment and impairment reversal note disclosure included in Note 5 of the accompanying financial statements in relation to this matter

Recoverability of deferred tax asset

The consolidated statement of financial position as at December 31, 2020 includes a deferred tax asset of $659 million. The deferred tax asset consists mainly of non-capital loss carry-forwards and deductible temporary differences related to scientific research and experimental development and asset retirement obligations. The recognition of deferred tax assets is based on management's judgement and estimate that it is probable taxable profit will be available against which these assets can be utilized. Refer to Note 1 for a description of the Company's tax accounting policy. Note 13 includes the disclosures for income taxes.

Auditing the Company's estimate of future taxable profit and the recoverability of the deferred tax asset was complex due to the subjective and sensitive nature of the various management inputs and assumptions. The primary inputs noted in the deferred tax asset recognition model were cash flows from the production of proved and probable reserves volumes, general and administrative and interest expenditures. The evaluation of this estimate required specialized skills and knowledge.

To test the Company's estimated recoverability of deferred tax assets, we performed the following procedures, among others:

- Evaluated the competence, capability and objectivity of the independent reservoir engineering specialist engaged by the Company as well as obtained an understanding of the work they performed. The appropriateness of their work as audit evidence was evaluated by considering the relevance and reasonableness of the methods and inputs utilized
- Compared forecast benchmark commodity price estimates of oil, natural gas, and NGLs against historically realized prices and to other third-party price forecasts
- Assessed forecasted production, royalty, operating cost, and capital cost data by comparing it to historical performance of the Company
- Involved our Canadian income tax specialists who assisted in evaluating the application of relevant tax laws and regulations used in the determination of the deferred income tax asset
- With the support of our tax specialists, tax pool balances were agreed to the most recent tax

filings, and the tax rates used in determining the deferred tax balances were compared against the enacted or substantively enacted tax rates

- Evaluated the adequacy of disclosure in Note 13 to the consolidated financial statements in respect of this matter

Other Information

Management is responsible for the other information. The other information comprises the Management's Discussion and Analysis.

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

In connection with our audit of the consolidated financial statements, our responsibility is to read the other information, and in doing so, consider whether the other information is materially inconsistent with the consolidated financial statements or our knowledge obtained in the audit or otherwise appears to be materially misstated.

We obtained Management's Discussion & Analysis prior to the date of this auditor's report. If, based on the work we have performed, we conclude that there is a material misstatement of this other information, we are required to report that fact. We have nothing to report in this regard.

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

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

In preparing the consolidated 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.

Auditor's Responsibilities for the Audit of the Consolidated Financial Statements

Our objectives are to obtain reasonable assurance about whether the consolidated financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's 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 these consolidated 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 consolidated 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 auditor's report to the related disclosures in the consolidated 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 auditor's 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 consolidated financial statements, including the disclosures, and whether the consolidated financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We 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.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the consolidated financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's 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 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 independent auditor's report is Robert Troy Jubenvill.

Ernst & Young LLP

Chartered Professional Accountants

Calgary, Alberta
March 2, 2021

CONSOLIDATED BALANCE SHEETS

($ thousands)

As at December 31	Note	2020	2019
ASSETS			
Current assets			
Cash and cash equivalents	17	4,590	6,016
Accounts receivable	14	99,986	118,632
Risk management – current	14	408	6,062
Prepaid expenses and other		9,931	10,975
		114,915	141,685
Lease receivable	9	2,758	4,768
Dissent payment entitlement	6	89,250	–
Investments in securities	7	59,529	156,889
Exploration and evaluation	4	612,129	650,414
Property, plant and equipment, net	5	1,959,603	1,914,074
Deferred income tax	13	658,811	663,475
		3,496,995	3,531,305
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current liabilities			
Accounts payable and accrued liabilities	14	152,756	204,818
Risk management – current	14	32,281	1,757
Asset retirement obligations and other – current	9	32,229	40,288
		217,266	246,863
Long-term debt	8	813,491	632,300
Risk management – long-term	14	19,441	6,275
Asset retirement obligations and other – long-term	9	409,016	562,687
		1,459,214	1,448,125
Commitments and contingencies	20		
Shareholders' equity			
Share capital	10	2,207,408	2,207,485
Accumulated deficit		(235,061)	(128,487)
Reserves	11	65,434	4,182
		2,037,781	2,083,180
		3,496,995	3,531,305

See the accompanying notes to these Consolidated Financial Statements

On behalf of the Board of Directors

/s/ J.H.T. Riddell
J.H.T. Riddell, Director

/s/ R.M. MacDonald
R.M. MacDonald, Director

March 2, 2021

CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

($ thousands, except as noted)

Year ended December 31	Note	2020	2019
Petroleum and natural gas sales		626,045	914,881
Royalties		(31,328)	(63,319)
Revenue	15	594,717	851,562
Gain (loss) on financial commodity contracts	14	8,874	(45,169)
		603,591	806,393
Expenses			
Operating expense		297,075	375,962
Transportation and NGLs processing		101,286	94,691
General and administrative		32,891	52,573
Share-based compensation	12	12,974	18,495
Depletion, depreciation and net impairment reversals	5	112,063	364,761
Exploration and evaluation	4	33,961	22,378
(Gain) loss on sale of oil and gas assets	5	8,674	(169,279)
Interest and financing		53,650	40,183
Accretion of asset retirement obligations	9	43,358	56,658
Change in asset retirement obligations	9	(91,253)	(107,301)
Closure costs	9	–	13,965
Transaction and reorganization costs		3,048	2,272
Foreign exchange		622	(13)
		608,349	765,345
Change in fair value of securities – warrants	7	(1,692)	(9,162)
Other loss	16	(6,011)	(7,462)
Income (loss) before tax		(12,461)	24,424
Income tax expense			
Deferred	13	10,232	112,280
		10,232	112,280
Net loss		(22,693)	(87,856)
Other comprehensive income (loss), net of tax	11		
Items that will be reclassified to net income (loss)			
Change in fair value of cash flow hedges, net of tax		(20,141)	(7,338)
Reclassification to net income (loss), net of tax		4,290	1,178
Items that will not be reclassified to net income (loss)			
Change in fair value of securities, net of tax	7	(15,845)	(110,442)
Comprehensive loss		(54,389)	(204,458)
Net loss per common share ($/share)	10		
Basic and diluted		(0.17)	(0.67)

See the accompanying notes to these Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF CASH FLOWS
($ thousands)

Year ended December 31	Note	2020	2019
Operating activities			
Net loss		(22,693)	(87,856)
Add (deduct):			
Items not involving cash	17	156,480	357,070
Asset retirement obligations settled	9	(34,994)	(29,441)
Change in non-cash working capital		(17,883)	15,921
Cash from operating activities		80,910	255,694
Financing activities			
Net draw (repayment) of revolving long-term debt	8	179,990	(182,700)
Lease liabilities – principal repayments	9	(7,556)	(7,457)
Common Shares issued, net of issue costs	10	15	38,845
Common Shares purchased under restricted share unit plan	12	(4,081)	(4,516)
Common Shares repurchased under NCIB	10	–	(14,391)
Cash from (used in) financing activities		168,368	(170,219)
Investing activities			
Property, plant and equipment and exploration		(220,775)	(404,118)
Sale of oil and gas assets	5	(479)	379,698
Investments	7	(11,667)	(55,143)
Proceeds on sale of investment in securities	7	–	13,551
Change in non-cash working capital		(17,100)	(32,487)
Cash used in investing activities		(250,021)	(98,499)
Net decrease		(743)	(13,024)
Foreign exchange on cash and cash equivalents		(683)	(255)
Cash and cash equivalents, beginning of year		6,016	19,295
Cash and cash equivalents, end of year		4,590	6,016
Supplemental cash flow information	17		

See the accompanying notes to these Consolidated Financial Statements

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

($ thousands, except as noted)

Year ended December 31	Note	2020		2019	
		Shares (000's)		*Shares (000's)*	
Share capital					
Balance, beginning of year		***133,337***	**2,207,485**	*130,326*	2,184,608
Issued	10	***2***	**19**	*5,919*	36,447
Common Shares purchased and cancelled under NCIB	10	***–***	**–**	*(2,622)*	(14,391)
Change in vested and unvested Common Shares for restricted share unit plan	12	***(1,055)***	**(96)**	*(286)*	821
Balance, end of year		***132,284***	**2,207,408**	*133,337*	2,207,485
Retained earnings (accumulated deficit)					
Balance, beginning of year			**(128,487)**		21,189
Net loss			**(22,693)**		(87,856)
Reclassification of accumulated losses on securities	7		**(83,881)**		(61,820)
Balance, end of year			**(235,061)**		(128,487)
Reserves	11				
Balance, beginning of year			**4,182**		44,732
Other comprehensive loss			**(31,696)**		(116,602)
Contributed surplus			**9,067**		14,232
Reclassification of accumulated losses on securities	7		**83,881**		61,820
Balance, end of year			**65,434**		4,182
Total shareholders' equity			**2,037,781**		2,083,180

See the accompanying notes to these Consolidated Financial Statements

1. Significant Accounting Policies

Paramount Resources Ltd. ("Paramount" or the "Company") is an independent, publicly traded, liquids-focused Canadian energy company that explores for and develops both conventional and unconventional petroleum and natural gas reserves and resources. The Company also pursues longer-term strategic exploration and pre-development plays and holds a portfolio of investments in other entities. Paramount's principal properties are located in Alberta and British Columbia.

Paramount is the ultimate parent company of a consolidated group of companies and is incorporated and domiciled in Canada. The address of its registered office is 2800, 421 – 7th Avenue S.W., Calgary, Alberta, Canada, T2P 4K9. The consolidated group includes wholly-owned subsidiaries Fox Drilling Limited Partnership ("Fox Drilling"), Cavalier Energy Inc. ("Cavalier") and MGM Energy.

These consolidated financial statements of the Company, as at December 31, 2020 and 2019 and for the years then ended (the "Consolidated Financial Statements"), were authorized for issuance by Paramount's Board of Directors on March 2, 2021.

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") on a historical cost basis, except for certain financial instruments. The Company's accounting policies have been applied consistently to all years presented. Amounts included in these Consolidated Financial Statements are stated in thousands of Canadian dollars, unless otherwise noted.

The financial statements of Paramount's subsidiaries and partnerships are prepared for the same reporting periods as the parent in accordance with the Company's accounting policies. All intercompany balances and transactions have been eliminated.

The preparation of these Consolidated Financial Statements requires the use of certain accounting estimates and also requires Management to exercise judgment in applying the Company's accounting policies. Areas involving a higher degree of judgment or complexity, and areas where assumptions and estimates are significant to the Consolidated Financial Statements, are described in Note 3.

a) Revenue Recognition

Petroleum and natural gas sales are recognized when the customer assumes control of the product. The transfer of control of petroleum and natural gas volumes generally coincides with the purchaser obtaining physical possession and title to such volumes.

The Company has accounted for its forward physical delivery sales contracts, which are entered into and continue to be held for the purpose of delivery of non-financial items as executory contracts, in accordance with its expected sale requirements. These contracts are not considered derivative financial instruments. Settlements of these physical contracts are recognized in revenue over the term of the contracts as physical delivery occurs.

Revenue for drilling services is recognized when the performance of services has been completed and the Company has the right to collect consideration commensurate with the value of the services provided. When the Company's drilling rigs (the "Rigs") drill on a property owned by Paramount, the Company capitalizes its working interest share of the drilling expenses and eliminates the associated drilling revenue.

b) Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash in bank accounts and, from time to time, term deposits, certificates of deposit and other highly liquid investments.

c) Trade and Other Receivables

Accounts receivable are carried at amortized cost and are recorded as corresponding amounts of revenue are recognized or costs are incurred on behalf of partners in connection with joint operations.

d) Exploration and Evaluation

Costs related to the exploration for and evaluation of hydrocarbons, including costs of acquiring unproved properties, drilling and completing exploratory wells and estimated asset retirement costs, are initially capitalized, pending determination of technical feasibility and commercial viability. If hydrocarbons are found, but further appraisal activity is required to determine commercial viability, the exploration and evaluation ("E&E") costs continue to be recognized as an asset. All such costs are subject to technical, commercial, and Management review at least annually to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery.

When the technical feasibility and commercial viability of a project have been established, the E&E costs are transferred to petroleum and natural gas assets, subject to an impairment assessment. When the Company determines that an E&E project is no longer viable or its carrying value exceeds its recoverable amount, an impairment charge is recognized.

Exploratory geological and geophysical costs, pre-license costs, and annual lease rentals are expensed as incurred.

e) Property, Plant and Equipment

Petroleum and natural gas assets are carried at cost, net of accumulated depletion, depreciation and impairment, and include costs related to drilling and completing development wells, infrastructure construction, successful E&E projects and estimated asset retirement costs.

Paramount's Rigs are carried at cost, net of accumulated depreciation and impairment. Costs incurred to improve the capabilities of the Rigs, extend their useful lives or replace significant components are capitalized. When a significant component is replaced, the carrying value of the replaced component is written-off. Costs incurred to maintain and repair the Rigs are expensed as incurred.

Other property, plant and equipment, including leasehold improvements, are carried at cost net of accumulated depreciation.

Depletion and Depreciation

The capitalized costs of developed oil and gas properties are depleted over estimated volumes of proved plus probable reserves using the unit-of-production method. In determining applicable depletion rates, estimated future development capital amounts ascribed to such reserves are included in the numerator. For purposes of these calculations, volumes of natural gas production and reserves are converted to barrels of oil equivalent using a ratio of six thousand cubic feet of natural gas to one barrel (6:1). Depletion rates are revised annually, or more frequently when events dictate. E&E costs are not depleted.

Capitalized costs of the majority of Paramount's production equipment and gathering systems are depleted on a unit-of-production basis over the volume of estimated proved plus probable reserves ascribed to the property to which they relate. Capitalized costs of processing plants and other major infrastructure assets are depreciated on a straight-line basis over their expected useful lives, which extend up to 40 years.

The Rigs are depreciated on a straight-line basis by component over their expected useful lives, which range between 5 and 20 years.

Leasehold improvements are depreciated over the term of the related lease. Other assets are depreciated using the declining balance method at rates ranging between 35 and 50 percent.

f) Impairment and Impairment Reversal of Non-Financial Assets

Carrying values of the Company's non-financial assets are reviewed at each reporting date to determine whether any indicators of impairment are present, or whether there are any indicators that an impairment charge recognized in prior periods may no longer exist or may have decreased. For the purpose of impairment testing, non-financial assets are generally grouped together into a cash-generating unit ("CGU"), which consists of the smallest group of assets that generate cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The Company's developed oil and gas properties include four CGUs: the Grande Prairie CGU, the Kaybob CGU, the Central Alberta CGU and the Northern CGU. The Company's E&E assets, consisting of undeveloped land, are aggregated together as a group of assets for the purpose of impairment testing.

If an indicator of impairment or impairment reversal is identified for a particular asset or CGU, its recoverable amount is estimated. If the carrying value of such asset or CGU exceeds its estimated recoverable amount, an impairment charge is recognized. If the estimated recoverable amount of an asset or CGU that was previously impaired exceeds its carrying value, impairment charges recognized in prior periods are reversed to a maximum of the carrying value that would have been determined, net of depletion and amortization, had no impairment charges been recognized for that CGU in prior periods.

The recoverable amount of an asset or CGU is the greater of its fair value less costs of disposal ("FVLCD") and its value in use ("VIU"). In assessing FVLCD, the Company estimates the value a potential purchaser would ascribe to an asset or CGU. For oil and gas properties, FVLCD is generally estimated based on expected after-tax future net cash flows from the production of proved plus probable reserves volumes using forecast commodity prices and costs, discounted using market-based rates. VIU is determined by estimating the present value of the future net cash flows expected to be derived from the continued use of the asset or CGU including the allocation of corporate costs.

g) Joint Arrangements

Paramount conducts its exploration and development activities independently, as well as jointly with others through jointly controlled assets and operations. All of the Company's current interests in joint arrangements are classified as joint operations. To account for these arrangements, Paramount recognizes its proportionate share of the related revenues, expenses, assets and liabilities of such joint operations.

Interests in joint ventures are accounted for using the equity method of accounting. The Company does not currently have any interests in joint arrangements that are classified as joint ventures.

h) Business Combinations and Goodwill

Business combinations are accounted for using the acquisition method of accounting. Under this method, the net identifiable assets acquired are measured at fair value on the acquisition date, except for deferred income tax amounts. Any excess of the consideration paid over the value of the net identifiable assets acquired is recognized as goodwill. Any deficiency in the consideration transferred compared to the value of the net identifiable assets acquired is recognized in earnings. Costs incurred to complete the business combination are expensed.

i) Capitalized Borrowing Costs

Borrowing costs directly associated with the acquisition, construction or production of a qualifying asset are capitalized while the asset is being constructed or otherwise prepared for its intended productive use. All other borrowing costs are expensed in the period incurred.

j) Provisions

A provision is recognized where the Company has a present legal and/or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation.

A provision for onerous contracts is recognized when the expected economic benefits to be derived by the Company from a contract are lower than the unavoidable cost of meeting the obligations under the contract. The provision is measured at the lower of the expected cost of terminating the contract and the present value of the expected net cost of the remaining term of the contract.

k) Asset Retirement Obligations

Asset retirement obligations arise from legal and/or constructive obligations to retire assets, including oil and gas wells, gathering systems and facilities at the end of their productive lives. The present value of an asset retirement obligation is recognized in the Consolidated Balance Sheet when incurred and a reasonable estimate of the cost of settlement can be made. The present value of the obligation is determined using the applicable credit-adjusted risk-free discount rate, after applying an estimated cost inflation factor, and is adjusted for the passage of time, which is recognized as accretion expense. The present values of estimated future asset retirement costs are capitalized as part of the carrying value of the related long-lived asset and depreciated on the same basis as the underlying asset. Revisions to the timing, anticipated cost, discount rate and inflation rate relating to the estimated liability are accounted for prospectively by recording an adjustment to the asset retirement obligation liability, with a corresponding adjustment to the carrying value of the related asset. Where changes to asset retirement obligations relate to properties which have a nil carrying value, the corresponding change is recorded in earnings.

Actual costs incurred on settlement are applied against the asset retirement obligation liability. Differences between the actual costs incurred and the liability accrued are recognized in earnings when the reclamation of a property is complete.

l) Foreign Currency Translation

The functional and presentation currency of Paramount and its subsidiaries is the Canadian dollar.

m) Estimates of Fair Value

Inputs used to estimate fair values incorporated in the preparation of the Consolidated Financial Statements are categorized into one of three levels of a fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. The three levels are defined as follows:

Level One – Inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that can be accessed at the measurement date.

Level Two – Inputs are based on information other than quoted prices included within Level One that are observable for the asset or liability, either directly or indirectly, including:

a) quoted prices for similar assets or liabilities in active markets;

b) quoted prices for identical or similar assets or liabilities in markets that are not active;

c) inputs other than quoted prices that are observable for the asset or liability, for example:
   i. interest rates and yield curves observable at commonly quoted intervals;
   ii. implied volatilities; and
   iii. credit spreads; and

d) market-corroborated inputs.

Level Three – Inputs are unobservable. Unobservable inputs are developed using the best information available in the circumstances, which may incorporate Paramount's own internally generated data.

n) Financial Instruments and Other Comprehensive Income

Financial Instruments

The Company is exposed to market risks from changes in commodity prices, interest rates, foreign currency rates, credit risk and liquidity risk. From time-to-time, Paramount enters into derivative financial instruments, such as interest rate swaps and financial commodity contracts, to manage these risks.

Financial instruments are measured at fair value on initial recognition. The measurement of a financial instrument in subsequent periods is dependent upon whether it has been classified as "fair value through profit or loss", "fair value through other comprehensive income ("OCI")" or "amortized cost".

Paramount's risk management assets and liabilities relating to financial commodity contracts are classified as fair value through profit or loss. Fair value through profit or loss financial instruments are measured at fair value, with changes in their fair values over time being recognized in net earnings. The fair values of the Company's risk management assets and liabilities relating to financial commodity contracts are estimated using a market approach incorporating level two fair value hierarchy inputs, including forward market curves and price quotes for similar instruments provided by financial institutions.

Investments in securities are classified as fair value through OCI. Financial assets that are classified as fair value through OCI are measured at fair value with changes in such fair values being accumulated in OCI until the asset is sold or derecognized. Upon the disposition or derecognition of investments in securities, amounts previously recorded in OCI in respect of such an investment are reclassified to retained earnings.

Investments in level one fair value hierarchy securities are carried at their period-end trading price (level one fair value hierarchy estimate). Estimates of fair values for investments in level three fair value hierarchy securities are based on valuation techniques that incorporate unobservable inputs (level three fair value hierarchy inputs). The valuation techniques utilize market-based metrics of comparable companies and transactions, indications of value based on equity transactions of the entities and other indicators of value including financial and operational results of the entities. Fair value estimates of level three fair value hierarchy securities are updated at each balance sheet date to confirm whether the carrying value of the investment continues to fall within a range of possible fair values indicated by such techniques. Changes in assumptions, as well as changes in judgments regarding comparable transactions and entities, could result in a material change in the estimated fair values of investments in level three fair value hierarchy securities in future periods.

The Dissent Payment Entitlement as described in Note 6 is a financial instrument measured at amortized cost and was recorded based on the estimated fair value determined at the close of business on the day prior to exercising the Company's right to dissent, using valuation techniques and assumptions that incorporate unobservable inputs (level three fair value hierarchy inputs), including market-based metrics of comparable companies and transactions and other indicators of value.

Financial liabilities, including related transaction costs, are measured at amortized cost using the effective interest method.

Hedge Accounting

Paramount's risk management assets and liabilities related to floating-to-fixed interest rate and electricity swaps are accounted for as cash flow hedges using hedge accounting. The Company applies hedge accounting to certain financial instruments when such instruments are formally documented and designated at inception as qualifying hedging relationships. The documentation includes identification of the hedging instrument, the hedged item, the nature of the risk being hedged, the Company's risk management objective and strategy for undertaking the hedge and how the hedging relationship will be assessed to meet hedge effectiveness requirements.

Hedge effectiveness is evaluated by assessing the critical terms of the hedging relationship at inception, at the end of each reporting date and upon a significant change in the circumstances affecting hedge effectiveness. For a cash flow hedge, the effective portion of the change in the unrealized fair value of the hedging instrument is recognized in OCI. Accumulated gains or losses are reclassified from OCI to earnings as amounts are settled throughout the term of the arrangement. Any portion of the change in the fair value of the hedging instrument related to hedge ineffectiveness is recognized in earnings.

Other Comprehensive Income

For Paramount, OCI is comprised of changes in the fair value of investments in securities and changes in the fair value of financial instruments where hedge accounting is applied (effective portion of hedge). Amounts recorded in OCI each period are presented in the Consolidated Statement of Comprehensive Income (Loss). Cumulative changes in OCI are included in Reserves, which is presented within Shareholders' Equity in the Consolidated Balance Sheet.

o) Impairment of Financial Assets

The Company recognizes provisions for expected credit losses upon the initial recognition of financial assets and re-assesses the provision at each reporting date. The provision is adjusted as a result of changes in historical default rates, age of balances outstanding and counterparty credit metrics.

p) Income Taxes

Paramount follows the liability method of accounting for income taxes. Under this method, a deferred income tax asset or liability is recognized in respect of any temporary difference between the carrying amount of an asset or liability reported in the Consolidated Financial Statements and its respective tax basis, using substantively enacted income tax rates. Deferred income tax balances are adjusted to reflect changes in substantively enacted income tax rates expected to apply when the underlying assets are realized or liabilities are settled, with adjustments being recognized in deferred tax expense in the period in which the change occurs.

Deferred income tax assets are recognized to the extent future realization is considered probable. The carrying value of deferred income tax assets are reviewed at each reporting date taking into consideration historical and expected future taxable income, expected reversals of temporary differences, anticipated timing of realization, tax basis carry-forward periods and other factors. Deferred income tax assets are de-recognized to the extent that it is probable that the carrying value of the asset will be realized.

q) Flow-Through Shares

The proceeds of flow-through share issuances are allocated between the sale of Paramount's class A common shares ("Common Shares") and the sale of tax benefits associated with the flow-through feature of the securities. Proceeds are first allocated to share capital based on the market price of Common Shares on the date the offering is priced, with the balance recorded as a liability based on the difference between the issue price and the market price of Common Shares. As qualifying expenditures intended for renunciation to subscribers are incurred, the Company recognizes a deferred tax liability, reduces the liability recorded and recognizes any difference as deferred tax expense.

r) Share-Based Compensation

Paramount Stock Option Plan

Paramount has a stock option plan that enables its Board of Directors or Compensation Committee to grant options to acquire Common Shares ("Paramount Options") to key employees and directors. Paramount Options generally vest over five years and expire within six years of the grant date. The provisions of the plan permit the Company to settle the Paramount Options in Common Shares of the Company or in cash.

The Company accounts for Paramount Options as equity-settled share-based compensation transactions. The aggregate grant date fair value of stock options awarded is recognized as share-based compensation expense over the applicable vesting period on a straight-line basis, with a corresponding increase in Contributed Surplus. The grant date fair value of Paramount Options is estimated using the Black-Scholes-Merton model, and such value is not adjusted in future periods. The amount of share-based compensation expense recognized each period reflects the portion of the vesting term that has elapsed and the estimated number of options that are expected to vest. That estimate is adjusted each period such that the cumulative amount recognized on the vesting date reflects the actual number of Paramount Options that ultimately vest. Upon the exercise of a Paramount Option, the Company transfers the cumulative amount recognized in Contributed Surplus in respect of that option to Share Capital.

Cavalier Stock Option Plan

Cavalier has a stock option plan that enables its Board of Directors to grant options to acquire common shares of Cavalier ("Cavalier Options") to key employees and directors. Cavalier Options generally vest over five years and expire within seven years of the grant date. The provisions of the stock option plan permit Cavalier to settle Cavalier Options in common shares of Cavalier or in cash, at the discretion of Cavalier. Cavalier Options are accounted for as equity-settled share-based compensation transactions.

Restricted Share Unit Plan

Paramount's cash bonus and restricted share unit ("RSU") plan provides that rights to Common Shares may be awarded to employees annually. An independent trustee purchases Common Shares in the open market and holds such shares until completion of the vesting period. Generally, the awards vest over two years. The unvested portion of an award is initially recorded as a reduction to Paramount's Share Capital. The cost of such awards is then recognized over the vesting period as share-based compensation expense, with a corresponding increase to Share Capital.

s) Net Income Per Share

Basic net income per share is calculated by dividing net income by the weighted average number of Common Shares outstanding during the year. Diluted net income per share is calculated by adjusting the weighted average number of Common Shares outstanding for potentially dilutive Common Shares related to Paramount Options. The number of dilutive Common Shares is determined using the treasury stock method. As Paramount Options can be exchanged for Common Shares, they are considered potentially dilutive and are included in the Company's diluted per share amounts when they are dilutive to net income per share.

t) Leases

The determination of whether an arrangement is, or contains a lease, is based on the substance of the arrangement at the date of inception and upon modifications. An arrangement is a lease when the terms of the agreement relate to the use of a specific asset and the lessee has the right to control the use of the specified asset.

Lessee

On the date a leased asset is first available for use by the Company, a right-of-use ("ROU") asset and a corresponding lease liability are recognized. The ROU asset is depreciated over the lease term and the lease liability is reduced as payments are made under the agreement. Each lease payment is allocated between a principal repayment and an interest component.

Assets and liabilities recognized in respect of leases are recorded on a discounted basis. Lease liabilities consist of the net present value of the aggregate contractual lease payments. Where the rate implicit in a lease is not readily determinable, lease payments are discounted using the Company's incremental borrowing rate. ROU assets are recognized at the amount corresponding to the amount of the initial lease liability. Lease payments in respect of short-term leases with terms of less than twelve months, or in respect of leases for which the underlying asset is of low value, are expensed as incurred.

Lessor

As a lessor, contractual arrangements which transfer substantially all of the risks and benefits of ownership of an asset to the lessee are accounted for as finance leases. Under a finance lease, the present value of the minimum lease payments receivable from the lessee are recorded as an account receivable. Lease payments received are applied against the receivable balance, with an interest component recognized as interest revenue.

If substantially all of the risks and benefits of ownership of an asset are not transferred to the lessee, the lease is classified as an operating lease and lease payments received are recognized as income over the term of the agreement.

2. New and Updated Accounting Policies and Standards

Financial Instruments

Effective January 1, 2020, the Company adopted the amendments to IFRS 9 – *Financial Instruments* ("IFRS 9"), IAS 39 – *Financial Instruments: Recognition and Measurement* ("IAS 39") and IFRS 7 – *Financial Instruments: Disclosures* ("IFRS 7"). These amendments provided relief on hedge accounting from the potential effects of the uncertainty arising from the phase-out of interest rate benchmarks, the Interbank Offered Rate ("IBOR") reform. The Company's floating-to-fixed interest rate swaps, which are described in Note 14, are impacted by these amendments as hedge accounting is applied to these instruments and hedging relationships may be impacted by the IBOR reform. There has been no impact on the recognized assets, liabilities or comprehensive loss of the Company resulting from the adoption of these amendments.

Government Grants

Government grants are recognized when there is reasonable assurance that the relevant conditions of the grant are met and that the grant will be received. The Company records the grant in the Consolidated Financial Statements with the related expenditure in the period in which the eligible costs are incurred. For the year ended December 31, 2020 the Company recognized $11.1 million relating to the Canada Emergency Wage Subsidy which reduced general and administrative expenses, operating expenses and capital expenditures by $6.4 million, $4.0 million and $0.7 million, respectively. Asset retirement obligation settlements approved for funding under government programs are recorded as a credit to earnings in change in asset retirement obligations in the period in which the related eligible costs are incurred (see Note 9).

Future Changes in Accounting Standards

In 2020, the IASB published phase two of its amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 – *Insurance Contracts* and IFRS 16 - *Leases* ("IFRS 16") to assist companies in applying IFRS Standards when changes are made to contractual cash flows or hedging relationships arising from the replacement of an interest rate benchmark with an alternative benchmark rate from IBOR reform. These amendments are effective for years beginning on or after January 1, 2021. Paramount expects that the amendments will not have a material impact on the Consolidated Financial Statements on adoption.

3. Significant Accounting Estimates, Assumptions & Judgments

The timely preparation of financial statements requires Management to make judgments, estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosures regarding contingent assets and liabilities. Estimates and assumptions are regularly evaluated and are based on Management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Changes in judgments, estimates and assumptions based on new information could result in a material change to the carrying amount of assets or liabilities and have a material impact on assets, liabilities, revenues and expenses recognized in future periods.

The course of the COVID-19 pandemic and its ultimate economic impact remain highly uncertain. The ultimate impact of the pandemic on Paramount's future operations and financial performance is unknown and will be dependent on a number of unpredictable factors outside of the knowledge and control of Management, including: (i) the duration and severity of the pandemic; (ii) the impact of the pandemic on economic growth, commodity prices and financial and capital markets; and (iii) governmental responses and restrictions. These uncertainties may continue to persist beyond the point where the outbreak of the COVID-19 virus has subsided. The potential impact of the COVID-19 pandemic has been considered by Management in making judgments, estimates and assumptions used in the preparation of these Consolidated Financial Statements, but the inherent risks and uncertainties resulting from the pandemic may result in material changes to such judgments, estimates and assumptions in future periods as additional information becomes available.

A description of the accounting judgments, estimates and assumptions that are considered significant is set out below.

Exploration or Development

The Company is required to apply judgment when designating a project as E&E or development, including assessments of geological and technical characteristics and other factors related to each project.

Exploration and Evaluation Projects

The accounting for E&E projects requires Management to make judgments as to whether exploratory projects have discovered economically recoverable quantities of petroleum and natural gas, which requires the quantity and realizable value of such petroleum and natural gas to be estimated. Previous estimates are sometimes revised as new information becomes available. Where it is determined that an exploratory project did not discover economically recoverable petroleum and natural gas, the costs are written-off as E&E expense.

If hydrocarbons are encountered, but further appraisal activity is required, the exploratory costs remain capitalized as long as sufficient progress is being made in assessing whether the recovery of the petroleum and natural gas is economically viable. The concept of "sufficient progress" is a judgmental area, and it is possible to have exploratory costs remain capitalized for several years while additional exploratory activities are carried out or the Company seeks government, regulatory or partner approval for development plans. E&E assets are subject to ongoing technical, commercial and Management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery. When Management is making this assessment, changes to project economics, expected quantities of petroleum and natural gas, expected production techniques, drilling results, estimated capital expenditures and production costs, results of other operators in the region and access to infrastructure and potential infrastructure expansions are important factors. Where it is determined that an exploratory project is not economically viable, the costs are written-off as E&E expense.

Reserves Estimates

Reserves engineering is an inherently complex and subjective process of estimating underground accumulations of petroleum and natural gas. The process relies on judgments based on the interpretation of available geological, geophysical, engineering and production data. The accuracy of a reserves estimate is a function of the quality and quantity of available data, the interpretation of such data, the accuracy of various economic assumptions and the judgment of those preparing the estimate. Because these estimates depend on many assumptions, all of which may differ from actual results, reserves estimates, and estimates of future net revenue will be different from the sales volumes ultimately recovered and net revenues actually realized. Changes in market conditions, regulatory matters, the results of subsequent drilling, testing and production and other factors may result in revisions to the original estimates.

Estimates of reserves impact: (i) the assessment of whether a new well has found economically recoverable reserves; (ii) depletion rates; (iii) the estimated fair value of petroleum and natural gas properties acquired in a business combination; and (iv) the estimated recoverable amount of petroleum and natural gas properties used for the purposes of impairment and impairment reversal assessments, all of which could have a material impact on earnings.

Business Combinations

Management is required to exercise judgment in determining whether assets acquired and liabilities assumed constitute a business. A business consists of an integrated set of assets and activities, comprised of inputs and processes, that is capable of being conducted and managed as a business by a market participant.

Business combinations are accounted for using the acquisition method of accounting, whereby the net identifiable assets acquired are recorded at fair value. The fair value of individual assets is often required to be estimated, which may involve estimating the fair values of proved plus probable reserves, contingent resources, tangible assets, undeveloped land, intangible assets and other assets. These estimates incorporate assumptions using indicators of fair value, as determined by Management. Changes in any of the estimates or assumptions used in determining the fair value of the net identifiable assets acquired may impact the carrying values assigned to assets acquired and liabilities assumed and could have a material impact on earnings.

Estimates of Recoverable Amounts

Estimates of recoverable amounts used in impairment and impairment reversal assessments often incorporate level three fair value hierarchy inputs, including estimated volumes and future net revenues from proved plus probable reserves, contingent resource estimates, future net cash flow estimates related to other long-lived assets and internal and external market metrics used to estimate value based on comparable assets and transactions. By their nature, such estimates are subject to measurement uncertainty. Changes in such estimates, and differences between actual and estimated amounts, could have a material impact on earnings.

Determination of CGUs

The recoverability of the carrying value of petroleum and natural gas assets is generally assessed at the CGU level. The determination of the properties and other assets grouped within a particular CGU is based on Management's judgment with respect to the integration between assets, shared infrastructure and cash flows, the overall significance of individual properties and the manner in which Management monitors its operations and allocates capital. Changes in the assets comprising CGUs could have an impact on estimated recoverable amounts used in impairment assessments and could have a material impact on earnings.

Depletion

Depletion rates are determined based on Management's estimates of the expected usage pattern of the Company's petroleum and natural gas assets, including assumptions regarding future production volumes and the useful lives of production equipment and gathering systems.

Dissent Payment Entitlement

The Dissent Payment Entitlement is a financial instrument measured at amortized cost and was recorded based on the estimated fair value thereof on initial recognition. Management exercised judgment in estimating the fair value of the Dissent Payment Entitlement through the use of available market inputs and other assumptions. On initial recognition and at the end of each period Management assess the Dissent Payment Entitlement for any expected credit loss. Changes in estimates of the initial fair value and the expected credit loss could have a material impact on the Dissent Payment Entitlement asset and on comprehensive income.

Investments in Securities

The Company's investments in securities are accounted for as fair value through OCI financial assets. Management is required to exercise judgment in estimating the fair value of investments in the securities of corporations that are not publicly traded using the Company's assessment of available market inputs and other assumptions. Changes in estimates of fair value for such investments could have a material impact on comprehensive income.

Provisions

A provision is recognized where the Company has determined that it has a present obligation arising from past events and the settlement of the obligation is expected to result in an outflow of economic benefits. The determination of whether the Company has a present obligation arising from past events requires Management to exercise judgement as to the facts and circumstances of the event and the extent of any expected obligations of Paramount. Changes in facts and circumstances as a result of new information and other developments may impact Management's assessment of the Company's obligations, if any, in respect of such events. Changes in such estimates could have a material impact on Paramount's assets, liabilities, revenues, expenses and earnings.

Asset Retirement Obligations

Estimates of asset retirement costs are based on assumptions regarding the methods, timing, economic environment and regulatory standards that are expected to exist at the time assets are retired. Management also exercises judgment to determine the credit-adjusted risk-free discount rate at the end of each reporting period which may change in response to numerous market factors. The Company adjusts estimated amounts periodically as assumptions are updated to incorporate new information. The actual amount and timing of payments to settle the obligations may differ materially from estimates.

Share-Based Payments

The Company estimates the grant date value of stock options awarded using the Black-Scholes-Merton model. The inputs used to determine the estimated value of the options are based on assumptions regarding share price volatility, the expected life of the options, expected forfeiture rates and future interest rates. By their nature, these inputs are subject to measurement uncertainty and require Management to exercise judgment.

Income Taxes

Accounting for income taxes is a complex process requiring Management to interpret frequently changing laws and regulations and make judgments and estimates related to the application of tax law, the timing of temporary difference reversals and the likelihood of realizing deferred income tax assets. All tax filings are subject to subsequent government audits and potential reassessment. These interpretations and judgments, and changes related to them, impact current and deferred income tax provisions, the carrying value of deferred income tax assets and liabilities and could have a material impact on earnings.

4. Exploration and Evaluation

Year ended December 31	2020	2019
Balance, beginning of year	650,414	719,908
Additions	3,294	5,643
Acquisitions	–	6,127
Change in asset retirement provision	(724)	(392)
Transfers to property, plant and equipment	(8,735)	(66,961)
Expired lease costs	(25,585)	(10,173)
Dispositions	(6,535)	(3,738)
Balance, end of year	612,129	650,414

Exploration and Evaluation Expense

Year ended December 31	2020	2019
Geological and geophysical	8,376	11,016
Expired lease costs and other	25,585	11,362
	33,961	22,378

At December 31, 2020, the Company assessed its E&E assets for indicators of potential impairment and none were identified.

5. Property, Plant and Equipment

Year ended December 31, 2020	Petroleum and natural gas assets	Drilling rigs	Right-of-use assets	Other	Total
Cost					
Balance, December 31, 2019	3,996,107	161,189	15,960	46,702	**4,219,958**
Additions	220,735	1,386	(228)	1,876	**223,769**
Transfers from exploration and evaluation	8,735	–	–	–	**8,735**
Dispositions	(35,767)	(99)	(273)	(525)	**(36,664)**
Change in asset retirement provision	(64,766)	–	–	–	**(64,766)**
Cost, December 31, 2020	4,125,044	162,476	15,459	48,053	**4,351,032**
Accumulated depletion, depreciation and impairment					
Balance, December 31, 2019	(2,177,753)	(89,871)	(5,296)	(32,964)	**(2,305,884)**
Depletion and depreciation	(238,655)	(10,130)	(3,618)	(4,675)	**(257,078)**
Net impairment reversals	141,857	–	–	–	**141,857**
Dispositions	28,818	99	244	515	**29,676**
Accumulated depletion, depreciation and impairment, December 31, 2020	(2,245,733)	(99,902)	(8,670)	(37,124)	**(2,391,429)**
Net book value, December 31, 2019	1,818,354	71,318	10,664	13,738	**1,914,074**
Net book value, December 31, 2020	1,879,311	62,574	6,789	10,929	**1,959,603**

Year ended December 31, 2019	Petroleum and natural gas assets	Drilling rigs	Right-of-use assets	Other	Total
Cost					
Balance, December 31, 2018	4,041,098	159,817	–	46,574	**4,247,489**
Right-of-use assets [(1)]	–	–	13,965	(4,434)	**9,531**
Balance, January 1, 2019	4,041,098	159,817	13,965	42,140	**4,257,020**
Additions	397,100	3,888	1,995	5,083	**408,066**
Transfers from exploration and evaluation	66,961	–	–	–	**66,961**
Dispositions	(411,872)	(2,516)	–	(521)	**(414,909)**
Change in asset retirement provision	(97,180)	–	–	–	**(97,180)**
Cost, December 31, 2019	**3,996,107**	**161,189**	**15,960**	**46,702**	**4,219,958**
Accumulated depletion, depreciation and impairment					
Balance, December 31, 2018	(1,961,290)	(78,865)	–	(29,153)	**(2,069,308)**
Right-of-use assets [(1)]	–	–	(2,158)	2,158	**–**
Balance, January 1, 2019	(1,961,290)	(78,865)	(2,158)	(26,995)	**(2,069,308)**
Depletion and depreciation	(343,781)	(13,327)	(3,138)	(6,223)	**(366,469)**
Dispositions	127,318	2,321	–	254	**129,893**
Accumulated depletion, depreciation and impairment, December 31, 2019	**(2,177,753)**	**(89,871)**	**(5,296)**	**(32,964)**	**(2,305,884)**
Net book value, December 31, 2018	2,079,808	80,952	–	17,421	**2,178,181**
Net book value, December 31, 2019	**1,818,354**	**71,318**	**10,664**	**13,738**	**1,914,074**

(1) Recognized on adoption of IFRS 16, which was effective January 1, 2019.

In December 2019, Paramount closed the sale of certain natural gas-weighted properties in West Central Alberta (the "West Central Alberta Assets") for gross cash proceeds of $52.4 million. A gain of $2.3 million was recognized on the sale. The West Central Alberta Assets were included in the Central Alberta CGU.

In August 2019, Paramount closed the sale of its Karr 6-18 natural gas facility and related midstream assets located in the Grande Prairie CGU for gross cash proceeds of $331.6 million. In connection with the sale, the Company entered into a midstream services agreement that includes a fee-for-service arrangement and a take-or-pay volume commitment that ends in 2040. A gain of $153.6 million was recognized on the sale.

Depletion, Depreciation and Net Impairment Reversals

Year ended December 31	2020	2019
Depletion and depreciation	253,920	364,761
Net impairment reversals of petroleum and natural gas assets	(141,857)	–
	112,063	364,761

At December 31, 2020, the Company recorded aggregate impairment reversals of $333.7 million from previously recorded impairment charges, comprised of $287.7 million, $30.6 million and $15.4 million related to petroleum and natural gas assets in the Kaybob, Northern and Central Alberta CGUs, respectively. The impairment reversals resulted from an increase in the estimated recoverable amount of such CGUs compared to the prior impairment assessment performed at March 31, 2020.

The $333.7 million aggregate impairment reversals represent the amount to bring the carrying values of the Kaybob and Northern CGUs to their estimated recoverable amounts and the carrying value of the Central Alberta CGU to the amount, net of depletion and amortization, had no impairment charges been recognized in prior periods. The increase in the estimated recoverable amount of these CGUs was mainly due to lower operating and capital costs than previously forecasted and changes to the development plan.

The recoverable amount of the Kaybob, Northern and Central Alberta CGUs as at December 31, 2020 was estimated on a FVLCD basis, using a discounted cash flow method (level 3 fair value hierarchy estimate). Cash flows were projected over the expected remaining productive life of the proved plus probable reserves assigned to the Kaybob, Northern and Central Alberta CGUs, at discount rates of 11.5 percent, 13.5 percent and 13.0 percent, respectively. Proved plus probable reserves estimates were prepared by Paramount's independent qualified reserves evaluator. The reserves evaluation process is inherently subjective and involves considerable estimation uncertainty.

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at December 31, 2020: [(1)]

(Average for the period)	2021	2022	2023	2024	2025	2026-2033	Thereafter
Natural Gas [(2)]							
AECO ($/MMBtu)	2.78	2.70	2.61	2.65	2.70	2.76 – 3.16	+2%/yr
Henry Hub (US$/MMBtu)	2.83	2.87	2.90	2.96	3.02	3.08 – 3.53	+2%/yr
Crude Oil and Condensate [(2)]							
Edmonton Condensate ($/Bbl)	59.24	63.19	67.34	69.77	71.18	72.61 – 83.44	+2%/yr
WTI (US$/Bbl)	47.17	50.17	53.17	54.97	56.07	57.19 – 65.70	+2%/yr
Foreign Exchange							
$US / 1 $CDN	0.77	0.77	0.76	0.76	0.76	0.76	0.76

(1) Average of forecasts published by: (i) McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. at January 1, 2021 and (ii) Sproule Associates Ltd. at December 31, 2020.
(2) Forecast benchmark prices are adjusted for quality differentials, heat content, distance to market and other factors in determining estimated recoverable amounts.

The following table summarizes the impact of a change to the discount rate or undiscounted cash flow estimates on the net impairment reversals as at December 31, 2020:

	Discount Rate		Cash Flow Estimates	
	One Percent Increase	One Percent Decrease	Five Percent Increase	Five Percent Decrease
Net impairment reversals – increase (decrease)	(55,455)	62,102	38,432	(38,432)

At March 31, 2020, the Company recorded impairments of $188.3 million and $3.5 million related to petroleum and natural gas assets in the Kaybob and Northern CGUs, respectively. The impairments were recorded because the carrying value of the CGUs exceeded their estimated recoverable amount, which were estimated based on expected net cash flows from the production of proved plus probable reserves ascribed to each CGU. The impairments resulted from decreases in estimated future net revenues, mainly due to lower forecasted oil and natural gas prices.

Recoverable amounts were estimated on a FVLCD basis using a discounted cash flow method (level three fair value hierarchy estimate). Cash flows were determined based on internally estimated after-tax discounted future net cash flows from the production of proved plus probable reserves assigned to the Kaybob and Northern CGUs, at discount rates of 11.5 percent and 13.5 percent, respectively. The net cash flows from the proved plus probable reserves estimated by Paramount's independent qualified reserves evaluator as at December 31, 2019 were internally updated by Management to reflect commodity price estimates at March 31, 2020 and for changes to certain operating and capital assumptions to reflect the prevailing economic environment. The reserves evaluation process is inherently subjective and involves considerable estimation uncertainty.

The following table sets out the forecast benchmark commodity prices and exchange rates used to determine estimated recoverable amounts at March 31, 2020: (1)

	(Apr-Dec) 2020	2021	2022	2023	2024	2025-2032	Thereafter
Natural Gas (2)							
AECO ($/MMBtu)	1.74	2.20	2.38	2.45	2.53	2.60-3.04	+2%/yr
Henry Hub (US$/MMBtu)	2.10	2.58	2.79	2.86	2.93	3.00-3.45	+2%/yr
Crude Oil and Condensate (2)							
Edmonton Condensate ($/Bbl)	34.35	50.72	62.80	68.49	71.73	73.16-84.23	+2%/yr
WTI (US$/Bbl)	29.17	40.45	49.17	53.28	55.66	56.87-65.33	+2%/yr
Foreign Exchange							
$US / 1 $CDN	0.71	0.73	0.75	0.75	0.75	0.75	0.75

(1) Average of forecasts published by: (i) McDaniel & Associates Consultants Ltd. and GLJ Petroleum Consultants Ltd. at April 1, 2020 and (ii) Sproule Associates Ltd. at March 31, 2020.
(2) Forecast benchmark prices are adjusted for quality differentials, heat content, distance to market and other factors in determining estimated recoverable amounts.

6. Dissent Payment Entitlement

As at December 31	2020	2019
Dissent Payment Entitlement	89,250	–

Paramount held 85 million common shares of Strath Resources Ltd. ("Strath") prior to its amalgamation with Cona Resources Ltd. in August 2020 to form Strathcona Resources Ltd. ("Strathcona"). Paramount objected to the amalgamation and exercised its right of dissent under section 191 of the *Business Corporations Act* (Alberta) (the "ABCA") with respect to its Strath shares. As a result, the Company is entitled to be paid in cash the fair value of its Strath shares, determined as of the close of business on July 24, 2020 (the "Dissent Payment Entitlement").

The amount of the Dissent Payment Entitlement and the timing of the payment thereof are uncertain. Paramount has applied to the Court of Queen's Bench of Alberta (the "Court") seeking Strathcona's payment of the Dissent Payment Entitlement. Strathcona made a statutorily required offer with respect to the Dissent Payment Entitlement in the amount of $45 million (the "Offered Amount"). Paramount has rejected such offer and applied to the Court for an interim payment of the Offered Amount pending final determination of the amount of the Dissent Payment Entitlement. In the event the parties are unable to agree on the amount of the Dissent Payment Entitlement, the final amount, including any interest thereon, will be determined by the Court. Any payment of the Dissent Payment Entitlement will be subject to the satisfaction by Strathcona of the solvency tests provided in the ABCA.

7. Investments in Securities

As at December 31	2020	2019
Level one fair value hierarchy securities	48,425	88,439
Level three fair value hierarchy securities	11,104	68,450
	59,529	156,889

For the year ended December 31, 2020, the Company recorded a charge of $18.1 million to OCI as a result of changes in the fair value estimates of investments in level one fair value hierarchy securities ("Level One Securities") and investments in level three fair value hierarchy securities ("Level Three Securities"). For the twelve months ended December 31, 2020, the Company recorded a loss of $1.7 million to net loss related to a change in the estimated fair value of warrants. Accumulated losses of $83.9 million were reclassified from accumulated OCI to accumulated deficit, which included $69.9 million related to the Company's exercise of its Strath dissent rights (see Note 6).

In 2020, the Company acquired 17.3 million common shares of NuVista Energy Ltd. ("NuVista Shares") at a price of $0.61 per share for an aggregate purchase price of $10.6 million. At December 31, 2020, the Company owned a total of 39.8 million NuVista Shares, representing 17.6 percent of the outstanding NuVista Shares, which were included in Investments in Securities and classified as Level One Securities.

In 2019, Paramount sold a portion of its investment in MEG Energy Corp. for cash proceeds of $13.6 million. As a result of the sale, $61.8 million of accumulated losses were reclassified from accumulated OCI to retained earnings.

Changes in the fair value of investments in securities are as follows:

Year ended December 31	2020	2019
Investments in securities, beginning of year	**156,889**	231,732
Changes in fair value of Level One Securities – recorded in OCI	**(50,632)**	6,330
Changes in fair value of Level Three Securities (1) – recorded in OCI	**32,547**	(118,104)
Transfer to Dissent Payment Entitlement (see note 6)	**(89,250)**	–
Changes in fair value of warrants (2) – recorded in earnings	**(1,692)**	(9,162)
Acquired – cash	**11,667**	55,143
Acquired – non-cash	**–**	4,501
Dispositions	**–**	(13,551)
Investments in securities, end of year	**59,529**	156,889

(1) Primarily related to the change in fair value of Strath common shares.
(2) Strathcona warrants (previously the Strath warrants).

8. Long-Term Debt

As at December 31	2020	2019
Paramount Facility	**813,491**	632,300

(1) December 31, 2020 Paramount Facility balance is presented net of $2.2 million in unamortized costs related to the June 2020 facility amendments.

Paramount Facility

The Company has a $1.0 billion financial covenant-based senior secured revolving bank credit facility (the "Paramount Facility"). The maturity date of the Paramount Facility is currently November 16, 2022, which may be extended from time to time at the option of Paramount and with the agreement of the lenders.

Borrowings under the Paramount Facility bear interest at the lenders' prime lending rate, US base rate, bankers' acceptance rate, or LIBOR, as selected at the discretion of the Company, plus a margin within a graduated range (the "Pricing Range") depending on the Company's prevailing Senior Secured Debt to Consolidated EBITDA ratio. The Paramount Facility is secured by a charge over substantially all of the assets of Paramount.

Paramount is subject to the following two financial covenants under the Paramount Facility (except during the period of financial covenant relief described further below) which are tested at the end of each fiscal quarter and calculated on a trailing twelve-month basis:

- Senior Secured Debt to Consolidated EBITDA to be 3.50 to 1.00 or less; and

- Consolidated EBITDA to Consolidated Interest Expense to be 2.50 to 1.00 or greater.

Senior Secured Debt currently consists of amounts drawn on the Paramount Facility and the undrawn face amounts of letters of credit outstanding under the Paramount Facility.

Consolidated EBITDA is adjusted for material acquisitions and dispositions and is generally calculated as net income before Consolidated Interest Expense, taxes, depletion, depreciation, amortization, impairment and E&E expense and is also adjusted to exclude non-recurring items and other non-cash items including unrealized mark-to-market amounts on derivatives, unrealized foreign exchange, share-based compensation expense and accretion.

Consolidated Interest Expense is reduced by customary exclusions including interest income.

In June 2020, the Paramount Facility was amended, which amendments included:

- a period of financial covenant relief to and including June 30, 2021 (the "Covenant Relief Period") providing for a full waiver of the Senior Secured Debt to Consolidated EBITDA covenant and a reduction of the Consolidated EBITDA to Consolidated Interest Expense covenant in certain periods;

- a decrease in the size of the Paramount Facility from $1.5 billion to $1.0 billion, with availability in excess of $900 million subject to certain new additional conditions (the "New Conditions"); and

- the margin applicable to credit facility drawings remaining at the highest end of the Pricing Range during the Covenant Relief Period.

In January 2021, the Paramount Facility was further amended to remove the New Conditions on availability in excess of $900 million. As a result, the full $1.0 billion capacity of the Paramount Facility is available.

During the Covenant Relief Period, Paramount was subject to the following financial covenant, tested at the end of each fiscal quarter:

Consolidated EBITDA to Consolidated Interest Expense to be:

- 1.75 to 1.00 or greater for the quarter ending December 31, 2020, calculated on a trailing twelve-month basis; and

- 1.75 to 1.00 or greater for the quarters ending March 31, 2021 and June 30, 2021, calculated on a current quarter basis.

Paramount was in compliance with the applicable financial covenant under the Paramount Facility at December 31, 2020.

Paramount elected to exit the Covenant Relief Period in March 2021, prior to its scheduled expiry on June 30, 2021.

Paramount had undrawn letters of credit outstanding under the Paramount Facility totaling $1.3 million at December 31, 2020 that reduce the amount available to be drawn on the Paramount Facility.

Unsecured Letter of Credit Facility

The Company has a $70 million unsecured demand revolving letter of credit facility (the "LC Facility") with a Canadian bank.

Paramount's obligations under the LC Facility are supported by a performance security guarantee ("PSG") from Export Development Canada ("EDC"). The PSG is valid to June 30, 2021 and may be extended at the option of Paramount and with the agreement of EDC. At December 31, 2020, $40.7 million in undrawn letters of credit were outstanding under the LC Facility.

9. Asset Retirement Obligations and Other

As at December 31, 2020	Current	Long-term	Total
Asset retirement obligations (1)	22,250	397,276	419,526
Lease liabilities	9,979	11,740	21,719
Asset retirement obligations and other	**32,229**	**409,016**	**441,245**

(1) Paramount received approval for up to $14 million of funding under the Alberta Site Rehabilitation Program (the "ASRP"), of which $4 million was used in 2020 and approximately $10 million remains available for use in 2021 and 2022.

As at December 31, 2019	Current	Long-term	Total
Asset retirement obligations	29,000	540,897	569,897
Lease liabilities	9,851	21,790	31,641
Flow-through share renunciation obligations (see note 10)	1,437	–	1,437
Asset retirement obligations and other	**40,288**	**562,687**	**602,975**

Asset Retirement Obligations

Year ended December 31	2020	2019
Asset retirement obligations, beginning of year	569,897	807,921
Additions	507	11,705
Change in estimates (1)	(7,605)	(171,404)
Change in discount rate	(145,178)	(33,269)
Obligations settled – cash	(34,994)	(29,441)
Obligations settled – funding under the ASRP (2)	(4,423)	–
Dispositions	(2,036)	(72,273)
Accretion expense	43,358	56,658
Asset retirement obligations, end of year	419,526	569,897

(1) Relates to changes in estimated costs and anticipated settlement dates of asset retirement obligations.
(2) Paramount received approval for up to $14 million of funding under the ASRP, of which $4 million was used in the fourth quarter of 2020.

As at December 31, 2020, estimated undiscounted, uninflated asset retirement obligations were $1,351.7 million (December 31, 2019 – $1,381.5 million). Asset retirement obligations have been determined using a credit-adjusted risk-free discount rate of 11.0 percent (December 31, 2019 – 8.0 percent) and an inflation rate of 2.0 percent (December 31, 2019 – 2.0 percent). These obligations are expected to be settled over the next 50 years.

For the year ended December 31, 2020, the Company recorded a recovery of $91.3 million (2019 - $107.3 million recovery) to earnings mainly related to changes in the discounted carrying value of estimated asset retirement obligations in respect of properties that had a nil carrying value. The recovery in 2020 mainly resulted from revisions in the credit-adjusted risk-free rate used to discount obligations and also included a recovery of $4 million of settlements funded under the ASRP.

Lease Liabilities

Paramount has lease liabilities in respect of office space and vehicles, which have been recognized at the discounted value of the remaining fixed lease payments. As at December 31, 2020 a weighted average incremental borrowing rate of approximately 9.0 percent (December 31, 2019 – 9.0 percent) was used to determine the discounted amount of the liabilities. For the year ended December 31, 2020, total cash payments made in respect of these lease liabilities, net of sublease arrangements, were $8.7 million (2019 - $9.0 million), of which $1.1 million (2019 - $1.5 million) was recognized as interest and financing expense.

For the twelve months ended December 31, 2020, expenses related to arrangements containing variable operating costs, short-term and low value leases which have not been included in the lease liability were approximately $3.3 million (2019 - $5.0 million).

As at December 31, 2020, $5.1 million (December 31, 2019 - $6.8 million) is due to the Company in respect of sublease arrangements for Paramount's office space, of which $2.3 million (December 31, 2019 - $2.0 million) was classified as current and $2.8 million (December 31, 2019 - $4.8 million) was classified as non-current. For the year ended December 31, 2020, $2.6 million (2019 - $2.3 million) was received in respect of office sublease arrangements, of which $0.4 million (2019 - $0.5 million) was recognized as interest revenue.

The minimum cash lease payments payable by the Company under these lease arrangements and receivable amounts due to the Company in respect of sublease arrangements are as follows:

	Lease Payments	Sublease Receivables
2021	10,954	2,591
2022	10,458	2,397
2023	2,280	502
	23,692	5,490

Closure costs

In the first quarter of 2019, the Company made the decision to cease its production operations at the Zama property in northern Alberta and commenced a closure program at the property. The Company recognized a provision of $14.0 million in respect of the expected costs of the program, of which the full $14.0 million was incurred to December 31, 2019.

10. Share Capital

Paramount's authorized share capital consists of an unlimited number of Common Shares without par value and an unlimited number of preferred shares issuable in series. At December 31, 2020, 132,284,323 (December 31, 2019 – 133,337,058) Common Shares of the Company were outstanding, net of 1,914,394 (December 31, 2019 – 859,659) Common Shares held in trust under the RSU plan, and no preferred shares were outstanding.

In November 2019, Paramount issued 5.9 million Common Shares on a "flow-through" basis in respect of Canadian development expenses at a price of $6.65 per share for gross proceeds of $39.2 million pursuant to a private placement. An entity controlled by the Company's President and Chief Executive Officer and Chairman acquired 3.8 million of the Common Shares under the private placement for $24.9 million. A liability of $2.6 million was initially recognized on the issuance of the flow-through shares in respect of the

Company's obligation to renounce qualifying expenditures. Paramount has since incurred sufficient qualifying expenditures to satisfy commitments associated with the flow-through share issuance.

In January 2020, Paramount implemented a normal course issuer bid program (the "2020 NCIB") under which the Company was permitted to purchase up to 7,044,289 Common Shares for cancellation. The Company did not purchase any Common Shares under the 2020 NCIB and the 2020 NCIB expired in January 2021.

Paramount previously implemented a normal course issuer bid program in January 2019 (the "2019 NCIB"). In 2019, the Company purchased and cancelled 2.6 million Common Shares at a total cost of $14.4 million under the 2019 NCIB.

Weighted Average Common Shares

Year ended December 31	2020		2019	
	Wtd. Avg Shares (000's)	**Net loss**	*Wtd. Avg Shares (000's)*	Net loss
Net loss – basic	***133,347***	**(22,693)**	*130,564*	(87,856)
Dilutive effect of Paramount Options	**–**	**–**	–	–
Net loss – diluted	***133,347***	**(22,693)**	*130,564*	(87,856)

Outstanding stock options that can be exchanged for the Company's Common Shares are potentially dilutive and are included in Paramount's diluted per share calculations when they are dilutive to net income per share. There were 9.7 million Paramount Options outstanding at December 31, 2020 (December 31, 2019 – 12.3 million), of which 9.7 million (December 31, 2019 – 12.3 million) were anti-dilutive.

11. Reserves

Reserves at December 31, 2020 include unrealized losses on cash flow hedges, unrealized gains and losses related to changes in the market value of investments in securities and contributed surplus amounts in respect of Paramount Options and Cavalier Options.

For the year ended December 31, 2020, accumulated losses of $83.9 million were reclassified from accumulated OCI to accumulated deficit related to the Company's exercise of its Strath dissent rights (see Note 6) and the derecognition of an investment classified as Level One Securities.

The changes in reserves are as follows:

Year ended December 31, 2020	Unrealized gains (losses) on cash flow hedges	Unrealized gains (losses) on securities	Contributed surplus	Total reserves
Balance, beginning of year	(6,160)	(147,674)	158,016	**4,182**
Other comprehensive loss, before tax	(20,616)	(18,085)	–	**(38,701)**
Deferred tax	4,765	2,240	–	**7,005**
Reclassification of accumulated losses on securities (see notes 6 and 7)	–	83,881	–	**83,881**
Share-based compensation (see note 12)	–	–	9,071	**9,071**
Paramount Options exercised	–	–	(4)	**(4)**
Balance, end of year	**(22,011)**	**(79,638)**	**167,083**	**65,434**

Year ended December 31, 2019	Unrealized gains (losses) on cash flow hedges	Unrealized gains (losses) on securities	Contributed surplus	Total reserves
Balance, beginning of year	–	(99,052)	143,784	**44,732**
Other comprehensive loss, before tax	(8,032)	(111,774)	–	**(119,806)**
Deferred tax	1,872	1,332	–	**3,204**
Reclassification of accumulated losses on securities (see note 7)	–	61,820	–	**61,820**
Share-based compensation (see note 12)	–	–	14,296	**14,296**
Paramount Options exercised	–	–	(64)	**(64)**
Balance, end of year	**(6,160)**	**(147,674)**	**158,016**	**4,182**

12. Share-Based Compensation

Paramount Options

	2020		2019	
	Number	Weighted average exercise price ($/share)	*Number*	Weighted average exercise price ($/share)
Balance, beginning of year	***12,311,462***	**12.16**	*12,465,163*	15.67
Granted	***3,111,500***	**3.82**	*3,565,930*	6.66
Exercised [1]	***(2,000)***	**7.28**	*(21,430)*	7.84
Cancelled or forfeited	***(4,366,829)***	**17.97**	*(3,683,801)*	18.73
Expired	***(1,372,738)***	**11.82**	*(14,400)*	11.90
Balance, end of year	***9,681,395***	**6.91**	*12,311,462*	12.16
Options exercisable, end of year	***2,416,871***	**9.74**	*4,442,966*	15.00

(1) For Paramount Options exercised during the twelve months ended December 31, 2020, the weighted average market price of Paramount's Common Shares on the dates exercised was $7.77 per share (2019 – $8.55 per share).

The weighted average remaining contractual life and exercise prices of Paramount Options outstanding as at December 31, 2020 are as follows:

	Awards Outstanding			Exercisable		
Exercise Prices	Number	Remaining contractual life (years)	Weighted average exercise price	Number	Remaining contractual life (years)	Weighted average exercise price
$1.64 - $3.84	3,096,500	5.3	3.80	10,000	4.3	1.64
$3.85 - $6.17	1,825,500	4.3	6.12	364,500	4.3	6.12
$6.18 - $7.28	2,694,000	3.4	7.24	1,040,700	3.4	7.25
$7.29 - $25.50	2,065,395	3.4	11.84	1,001,671	2.9	13.73
	9,681,395	**4.2**	**6.91**	**2,416,871**	3.3	**9.74**

The grant date fair value of Paramount Options and related weighted average inputs, estimated using the Black-Scholes-Merton model, are as follows:

	Options awarded in 2020	Options awarded in 2019
Weighted average exercise price ($ / share)	3.82	6.66
Volatility (%)	50	42
Expected life of share options (years)	3.9	3.8
Pre-vest annual forfeiture rate (%)	13.2	11.3
Risk-free interest rate (%)	0.4	1.6
Expected dividend yield (%)	Nil	Nil
Weighted average fair value of awards per option ($ / option)	1.43	2.19

The expected life of Paramount Options is based on historical exercise patterns. Volatility is generally estimated based on the historical volatility of the trading price of the Company's Common Shares over the most recent period that is commensurate with the expected term of the option, and is normalized for significant transactions and other factors.

Cavalier Options

In 2017, Cavalier granted 5.0 million Cavalier Options, which vest over five years and expire approximately eight years from the grant date. As at December 31, 2020, there were 3.7 million Cavalier Options outstanding and no Cavalier Options have been exercised.

Restricted Share Units – Shares Held in Trust

	2020		2019	
Year ended December 31	***Shares (000's)***		***Shares (000's)***	
Balance, beginning of year	*860*	1,388	*574*	2,209
Shares purchased	*1,600*	4,081	*713*	4,516
Change in vested and unvested shares	*(545)*	(3,985)	*(427)*	(5,337)
Balance, end of year	*1,915*	1,484	*860*	1,388

Employee Benefit Costs

Year ended December 31	**2020**	**2019**
Stock option plans	9,072	14,296
RSU plan	3,902	4,199
Share-based compensation expense	12,974	18,495
Salaries and benefits, net of recoveries	22,670	37,949
	35,644	56,444

13. Income Tax

The following table reconciles income taxes calculated at the Canadian statutory rate to Paramount's recorded income tax expense:

Year ended December 31	2020	2019
Income (loss) before tax	(12,461)	24,424
Effective Canadian statutory income tax rate	24.1%	26.5%
Expected income tax expense (recovery)	(3,003)	6,472
Effect on income taxes of:		
Change in statutory and other rates	4,188	101,200
Share-based compensation	2,186	3,788
(Gain) loss on sale of oil and gas assets	394	(17,019)
Change in value of investments	408	2,428
Change in unrecognized deferred income tax asset	4,746	1,867
Flow-through share renunciations	3,617	2,914
Non-deductible items and other	(2,304)	10,630
Income tax expense	10,232	112,280

The following table summarizes the components of the deferred income tax asset:

As at December 31	2020	2019
Property, plant and equipment	(302,438)	(336,024)
Investments	(524)	(2,765)
Asset retirement obligations	96,524	130,568
Non-capital losses and scientific research & experimental development	843,458	861,338
Other	21,791	10,358
Deferred income tax asset	658,811	663,475

The following table summarizes movements in the deferred income tax asset during the year:

Year ended December 31	2020	2019
Deferred income tax asset, beginning of year	663,475	773,575
Deferred income tax expense	(10,232)	(112,280)
Deferred income tax recovery included in OCI	7,006	3,204
Flow-through share renunciation	(1,437)	(1,158)
Share issuance costs	–	133
Other	(1)	1
Deferred income tax asset, end of year	658,811	663,475

As at December 31, 2020, Paramount had approximately $3.4 billion (December 31, 2019 – $3.4 billion) of unused non-capital losses that expire between 2032 and 2036. The Company has $160.7 million (December 31, 2019 – $154.9 million) of deductible temporary differences for which no deferred income tax asset has been recorded.

14. Financial Instruments and Risk Management

Financial Instruments

Financial instruments at December 31, 2020 consist of accounts receivable, risk management assets and liabilities, the Dissent Payment Entitlement, investments in securities, accounts payable and accrued liabilities and the Paramount Facility. The carrying values of these financial instruments approximate their fair values.

Risk Management

Assets

As at December 31	2020	2019
Financial commodity contracts – current	–	6,062
Electricity swaps – current	408	–
Risk management asset	**408**	6,062

Liabilities

As at December 31	2020	2019
Interest rate swaps – current	(9,616)	(1,757)
Financial commodity contracts – current	(22,665)	–
Risk management – current	(32,281)	(1,757)
Interest rate swaps – long-term	(19,441)	(6,275)
Risk management liability	**(51,722)**	(8,032)

From time-to-time, Paramount enters into derivative financial instruments to manage commodity price, interest rate, and foreign currency exchange risks.

The fair values of risk management financial instruments are estimated using a market approach incorporating level two fair value hierarchy inputs, including forward market curves and price quotes for similar instruments, provided by financial institutions.

Changes in the fair value of risk management assets are as follows:

Year ended December 31	2020	2019
Fair value, beginning of year	6,062	64,441
Changes in fair value – financial commodity contracts	31,539	(45,169)
Changes in fair value – electricity swaps	408	–
Settlements received – financial commodity contracts	(37,601)	(13,210)
Fair value, end of year	**408**	6,062

Changes in the fair value of risk management liabilities are as follows:

Year ended December 31	2020	2019
Fair value, beginning of year	(8,032)	–
Changes in fair value – interest rate swaps	(26,608)	(9,568)
Changes in fair value – financial commodity contracts	(22,665)	–
Settlements paid – interest rate swaps	5,583	1,536
Fair value, end of year	**(51,722)**	(8,032)

The Company had the following financial commodity contracts in place at December 31, 2020:

Instruments	Aggregate notional	Average fixed price	Fair value	Remaining term
Oil – NYMEX WTI Swaps (Sale)	5,000 Bbl/d	US$44.10/Bbl	(9,631)	January 2021 – December 2021
Oil – NYMEX WTI Swaps (Sale)	15,000 Bbl/d	US$43.29/Bbl	(9,193)	January 2021 – March 2021
Oil – NYMEX WTI Swaps (Sale)	15,000 Bbl/d	US$45.60/Bbl	(5,180)	April 2021 – June 2021
Oil – NYMEX WTI Swaps (Sale)	10,000 Bbl/d	US$46.76/Bbl	(1,605)	July 2021 – September 2021
Oil – NYMEX WTI Swaps (Sale)	5,000 Bbl/d	US$47.54/Bbl	(44)	October 2021 – December 2021
Oil – Edmonton Condensate WTI Differential Swap (Sale)	1,000 Bbl/d	WTI+US$0.50/Bbl	56	January 2021 – March 2021
Gas – NYMEX Swaps (Sale)	60,000 MMBtu/d	US$2.71/MMBtu	1,520	January 2021 – December 2021
Gas – NYMEX Swaps (Sale)	30,000 MMBtu/d	US$2.92/MMBtu	1,412	January 2021 – March 2021
			(22,665)	

Subsequent to December 31, 2020, the Company entered into the following financial commodity contracts:

Instruments	Aggregate notional	Average fixed price	Remaining term
Oil – NYMEX WTI Swaps (Sale)	3,000 Bbl/d	CDN$65.93/Bbl	April 2021 – June 2021
Oil – NYMEX WTI Swaps (Sale)	3,000 Bbl/d	CDN$64.67/Bbl	July 2021 – September 2021
Oil – NYMEX WTI Swaps (Sale)	7,000 Bbl/d	US$58.06/Bbl	February 2021
Oil – NYMEX WTI Swaps (Sale)	7,000 Bbl/d	US$59.21/Bbl	March 2021
Oil – NYMEX WTI Swaps (Sale)	3,000 Bbl/d	US$58.30/Bbl	April 2021 – June 2021
Oil – Edmonton Condensate WTI Differential Swap (Sale)	4,000 Bbl/d	WTI + US$0.06/Bbl	April 2021 – June 2021

The Company had the following floating-to-fixed interest rate and electricity swaps in place at December 31, 2020:

Contract type	Aggregate notional	Remaining term	Average fixed contract rate	Reference	Fair value
Interest Rate Swaps	$250 million	January 2021 - January 2023	2.3%	CDOR (1)	(9,221)
Interest Rate Swaps	$250 million	January 2021 - January 2026	2.4%	CDOR (1)	(19,836)
Electricity Swaps	5 MWh/d (2)	January 2021 - December 2021	$51.68/MWh	AESO Pool Price (3)	408
					(28,649)

(1) Canadian Dollar Offered Rate.
(2) "MWh" means MegaWatt hour.
(3) Floating hourly rate established by the Alberta Electric System Operator.

In 2019, Paramount entered into interest rate swaps to manage the uncertainty of variable interest rates by fixing the underlying CDOR interest rate on a portion of the Company's long-term debt. The Company classified these arrangements as cash flow hedges and has applied hedge accounting. There is an economic relationship between the hedged items and hedging instruments as the timing and amount of the cash flows received from the interest rate swaps matched the terms of the expected highly probable forecast transactions, which is the underlying CDOR amount of interest paid on $500 million of the Company's long-term debt. A hedge ratio of 1 to 1 was established as the underlying risk of the interest rate swaps were identical to the hedged risk components. As at December 31, 2020, there were no changes to the critical terms of the hedging relationship and no hedge ineffectiveness was identified.

In the third quarter of 2020, Paramount entered into floating-to-fixed price swaps to manage exposure to the variable market price of electricity by fixing the underlying AESO Pool Price on a portion of the Company's power. The Company classified these arrangements as cash flow hedges and has applied hedge accounting. As at December 31, 2020, there were no changes to the critical terms of the hedging relationship and no hedge ineffectiveness was identified.

Commodity Price Risk

Paramount uses financial commodity contracts from time-to-time to manage exposure to commodity price volatility. The Company is exposed to commodity price risk on these instruments, as changes in underlying commodity prices will impact the market values of the contracts and ultimately the amounts received or paid upon settlement.

A US$5.00 per barrel increase or decrease in the price of WTI crude oil, assuming all other variables are held constant, would have impacted net loss for the year ended December 31, 2020 by $30.1 million from changes in Paramount's outstanding financial commodity contracts as at December 31, 2020. A US$0.30 per MMBtu increase or decrease in the price of NYMEX Henry Hub natural gas, assuming all other variables are held constant, would have impacted net loss for the year ended December 31, 2020 by $7.5 million from changes in the Company's outstanding financial commodity contracts as at December 31, 2020.

Foreign Currency Risk

Paramount uses financial commodity contracts denominated in U.S. dollars from time-to-time to manage exposure to commodity price volatility and receives a portion of its revenues in U.S. dollars. A 10 percent increase or decrease in foreign exchange rates, assuming all other variables are held constant, would have impacted net loss for the year ended December 31, 2020 by $0.8 million from changes in the Company's U.S. dollar denominated financial instruments outstanding at December 31, 2020.

Credit Risk

Paramount is exposed to credit risk on its financial instruments where a financial loss would be experienced if a counterparty to a financial asset failed to meet its obligations. The maximum credit risk exposure at December 31, 2020 is limited to the carrying value of accounts receivable, risk management assets and the Dissent Payment Entitlement.

Paramount's primary objectives with respect to financial assets are to minimize financial risk and maintain high levels of liquidity. The Company's risk management assets are held with financial institutions with investment grade credit ratings and are highly liquid. Accounts receivable include balances due from customers and partners in the oil and gas industry and are subject to normal industry credit risk. The Company manages credit risk by endeavoring to enter into commodity contracts with counterparties that possess high credit ratings, employing net settlement agreements, employing letters of credit and limiting available credit when necessary. The change in the fair value of risk management contracts attributable to changes in counterparty credit risk is immaterial, as the counterparties to such contracts have investment grade credit ratings.

Interest Rate Risk

Paramount is exposed to interest rate risk on outstanding balances on the Paramount Facility and on interest bearing cash and cash equivalents. From time-to-time, the Company may enter into interest rate swaps to manage exposure to changes in interest rates on long-term debt.

A one percent increase in interest rates would have reduced Paramount's net earnings for the year ended December 31, 2020 by approximately $1.4 million (2019 - $1.7 million) based on the average floating rate credit facility balances and floating-to-fixed interest rate swaps outstanding during the year. A one percent decrease would have had the opposite effect.

Liquidity Risk

Liquidity risk is the risk that Paramount will be unable to meet its financial obligations as they become due. The Company manages liquidity risk by ensuring that it has sufficient cash and cash equivalents, credit facilities and other financial resources available to meet its obligations.

The Company forecasts cash flows for a period of at least 12 months to identify financial requirements. These requirements are met through a combination of cash flows from operations, cash and cash equivalents, and if required, credit facilities, the sale of assets and capital market transactions.

The Company's contractual obligations related to financial liabilities are as follows: [(1)]

	2021	2022	Total
Accounts payable & accrued liabilities	152,756	–	152,756
Paramount Facility	–	815,668	815,668
	152,756	**815,668**	**968,424**

(1) Excludes payments related to lease liabilities (see Note 9) and risk management liabilities.

Accounts Payable and Accrued Liabilities

As at December 31	2020	2019
Trade and accrued payables	**141,224**	178,105
Joint operation and other payables	**11,532**	26,713
	152,756	204,818

Trade and accrued payables and joint operation and other payables are non-interest bearing and are normally settled within 30 to 60 days.

Accounts Receivable

As at December 31	*2020*	2019
Revenue receivable	**72,916**	86,362
Joint operation receivable and other	**27,070**	32,270
	99,986	118,632

Revenue and joint operation receivables are non-interest bearing and are generally settled on 30-day terms. Accounts receivable that share similar credit risk characteristics are assessed for expected credit losses at each reporting date, including for changes in historical default rates, ages of balances outstanding and counterparty credit metrics. The total expected credit loss on the Company's accounts receivable was approximately 5 percent as at December 31, 2020 (December 31, 2019 – 2 percent).

For the year ended December 31, 2020, the Company had sales to one customer which exceeded ten percent of total revenue. Sales to such customers totaled $176.8 million.

15. Revenue By Product

Year ended December 31	2020	2019
Natural gas	204,946	261,006
Condensate and oil	383,752	610,203
Other natural gas liquids	24,747	37,651
Royalty and other	12,600	6,021
Royalties	(31,328)	(63,319)
	594,717	851,562

16. Other Loss

Year ended December 31	2020	2019
Interest income	65	324
Dispute settlements (see note 20)	–	(2,513)
Provision	(4,669)	–
Other	(1,407)	(5,273)
	(6,011)	(7,462)

In the first quarter of 2020, a provision of $4.7 million was recorded related to a pending partner dispute.

17. Consolidated Statements of Cash Flows - Selected Information

Items Not Involving Cash

Year ended December 31	2020	2019
Financial commodity contracts	28,727	58,379
Share-based compensation	12,974	18,495
Depletion, depreciation and net impairment reversals	112,063	364,761
Exploration and evaluation	25,585	11,362
(Gain) loss on sale of oil and gas assets	8,674	(169,279)
Accretion of asset retirement obligations	43,358	56,658
Change in asset retirement obligations	(91,253)	(107,301)
Foreign exchange	683	254
Change in fair value of securities - warrants	1,692	9,162
Deferred income tax	10,232	112,280
Other	3,745	2,299
	156,480	357,070

Supplemental Cash Flow Information

Year ended December 31	2020	2019
Interest paid	47,780	36,402

Components of Cash and Cash Equivalents

As at December 31	2020	2019
Cash	4,590	6,016
Cash equivalents	–	–
	4,590	6,016

18. Capital Structure

Paramount's primary objectives in managing its capital structure are to:

i. maintain a flexible capital structure which optimizes the cost of capital at an acceptable level of risk;
ii. maintain sufficient liquidity to support ongoing operations, capital expenditure programs, strategic initiatives and the settlement of obligations when due; and
iii. maximize shareholder returns.

Paramount manages its capital structure to support current and future business plans and periodically adjusts the structure in response to changes in economic conditions and the risk characteristics of the Company's underlying assets and operations. Paramount may adjust its capital structure through a number of means, including by issuing or repurchasing shares, altering debt levels, modifying capital spending programs, acquiring or disposing of assets and participating in joint ventures, the availability of any such means being dependent upon market conditions.

Paramount's capital structure consists of the following:

As at December 31	2020	2019
Adjusted working capital deficit (1)	40,599	71,217
Paramount Facility	813,491	632,300
Net Debt	854,090	703,517
Share capital	2,207,408	2,207,485
Accumulated deficit	(235,061)	(128,487)
Reserves	65,434	4,182
Total Capital	2,891,871	2,786,697

(1) Adjusted working capital excludes risk management assets and liabilities, current accounts receivable relating to subleases (December 31, 2020 – $2.3 million, December 31, 2019 – $2.0 million) and the current portion of asset retirement obligations and other.

19. Compensation of Key Management Personnel

Year ended December 31	2020	2019
Salaries and benefits	2,082	2,225
Share-based compensation	1,485	3,497
	3,567	5,722

20. Commitments and Contingencies

Paramount had the following commitments as at December 31, 2020:

	Within one year	After one year but not more than five years	More than five years
Petroleum and natural gas transportation and processing commitments (1)	259,082	889,436	1,174,429
Other commitments	4,532	17,809	–
	263,614	907,245	1,174,429

(1) Certain of the transportation and processing commitments are secured by outstanding letters of credit totaling $13.2 million at December 31, 2020 (December 31, 2019 – $10.2 million)

Commitments – Physical Sale Contracts

The Company had the following AECO natural gas fixed-price physical contracts in place at December 31, 2020:

Quantity	Location	Average fixed price	Remaining term
40,000 GJ/d	AECO	CDN$2.68/GJ	January 2021 – March 2021
50,000 GJ/d	AECO	CDN$2.51/GJ	January 2021 – December 2021

Subsequent to December 31, 2020, the Company entered into the following AECO natural gas fixed-price physical contracts:

Quantity	Location	Average fixed price	Remaining term
50,000 GJ/d	AECO	CDN$2.52/GJ	April 2021– October 2021

Contingencies

In the normal course of Paramount's operations, the Company may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty. Paramount does not anticipate that these claims will have a material impact on its financial position.

Tax and royalty legislation and regulations, and government interpretation and administration thereof, continually change. As a result, there are often tax and royalty matters under review by relevant government authorities. All tax and royalty filings are subject to subsequent government audit and potential reassessments. Accordingly, the final amounts may differ materially from amounts estimated and recorded.

Dispute Settlements

In the first quarter of 2020, Paramount reached an agreement to settle its dispute with respect to an alleged obligation to contribute to the costs related to the remediation of a release from a non-operated pipeline. Also in the first quarter of 2020, but unrelated to this settlement, the Company reached an agreement to settle a legal action involving the Company as plaintiff against a third-party supplier respecting defective products and services provided to the Company. The Company recognized a charge of $2.5 million in the fourth quarter of 2019 in respect of these settlements.

21. Subsequent Events

Convertible Debentures

In January 2021, the Company completed a private placement of $35.0 million of senior unsecured convertible debentures (the "Debentures"). An entity controlled by Paramount's President and Chief Executive Officer and Chairman purchased $25.0 million of the Debentures. An entity controlled by the Company's Executive Vice President, Corporate Development and Planning, purchased $0.1 million of the Debentures. The Debentures mature on January 31, 2024 (the "Maturity Date"), bear interest at 7.50 percent per annum payable monthly in arrears and are convertible by the holder into Common Shares at any time prior to the Maturity Date at a conversion price of $6.72 per Common Share prior to January 31, 2022, $7.33 per Common Share on or after January 31, 2022 and prior to January 31, 2023 and $7.94 per Common Share on or after January 31, 2023.

The Debentures are redeemable by Paramount, in whole or in part, at any time prior to the Maturity Date, at a redemption price (expressed as percentages of principal amount) equal to 107.50 percent prior to January 31, 2022, 103.75 percent on or after January 31, 2022 and prior to January 31, 2023 and 101.875 percent on or after January 31, 2023.

Asset Dispositions

In the first quarter of 2021, the Company sold certain non-core properties in the Kaybob and Central Alberta Regions for aggregate cash proceeds of approximately $80 million.

PRODUCT TYPE INFORMATION

This document refers to sales volumes of "liquids", "natural gas", "condensate and oil" and "other NGLs". "Liquids" means NGLs (including condensate) and oil combined, "natural gas" refers to conventional natural gas and shale gas combined, "condensate and oil" refers to condensate, light and medium crude oil and tight oil combined and "other NGLs" refers to ethane, propane and butane. Below is a complete breakdown of sales volumes for applicable periods by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil. Numbers may not add due to rounding.

	Annual							
	Total		Grande Prairie Region		Kabob Region		Central Alberta and Other Region	
	2020	2019	2020	2019	2020	2019	2020	2019
Shale gas (MMcf/d)	156.7	166.0	77.2	78.0	43.8	50.3	35.7	37.7
Conventional natural gas (MMcf/d)	92.0	137.3	1.4	1.5	82.1	95.9	8.5	39.9
Natural gas (MMcf/d)	248.7	303.3	78.6	79.5	125.9	146.2	44.2	77.6
Condensate (Bbl/d)	19,334	19,746	15,991	13,920	2,885	4,361	458	1,464
Other NGLs (Bbl/d)	4,325	6,767	1,964	1,814	1,812	2,476	549	2,477
NGLs (Bbl/d)	23,659	26,513	17,955	15,734	4,697	6,837	1,007	3,941
Tight oil (Bbl/d)	462	631	–	–	301	360	161	271
Light and Medium crude oil (Bbl/d)	2,768	4,703	14	53	2,709	3,929	46	721
Crude oil (Bbl/d)	3,230	5,334	14	53	3,010	4,289	207	992
Total (Boe/d)	68,340	82,394	31,076	29,040	28,685	35,500	8,579	17,854

	Q4							
	Total		Grande Prairie Region		Kabob Region		Central Alberta and Other Region	
	2020	2019	2020	2019	2020	2019	2020	2019
Shale gas (MMcf/d)	170.7	176.6	92.7	91.5	41.9	48.3	36.1	36.8
Conventional natural gas (MMcf/d)	85.6	122.4	1.6	1.9	76.3	89.1	7.7	31.4
Natural gas (MMcf/d)	256.3	299.0	94.3	93.4	118.2	137.4	43.8	68.2
Condensate (Bbl/d)	22,782	23,956	19,635	18,760	2,631	3,899	515	1,298
Other NGLs (Bbl/d)	4,987	7,064	2,429	2,376	1,953	2,504	605	2,184
NGLs (Bbl/d)	27,769	31,020	22,064	21,136	4,584	6,403	1,120	3,482
Tight oil (Bbl/d)	437	745	–	–	299	541	138	203
Light and Medium crude oil (Bbl/d)	2,533	3,815	–	91	2,480	3,331	54	393
Crude oil (Bbl/d)	2,970	4,560	–	91	2,779	3,872	192	596
Total (Boe/d)	73,460	85,411	37,782	36,789	27,056	33,167	8,622	15,455

	Karr				Wapiti			
	Q4		Annual		Q4		Annual	
	2020	2019	2020	2019	2020	2019	2020	2019
Shale gas (MMcf/d)	69.6	68.6	55.6	67.2	22.8	22.9	21.5	10.8
Conventional natural gas (MMcf/d)	0.9	0.5	0.7	0.5	0.5	0.7	0.4	0.3
Natural gas (MMcf/d)	70.5	69.1	56.3	67.7	23.3	23.6	21.9	11.1
NGLs (Bbl/d)	15,165	13,430	11,389	11,477	6,875	7,571	6,550	4,223
Total (Boe/d)	26,914	24,943	20,777	22,755	10,764	11,498	10,207	6,082

The Company forecasts that 2021 sales volumes will average between 77,000 Boe/d and 80,000 Boe/d (55% shale gas and conventional natural gas combined, 39% light and medium crude oil, tight oil and condensate combined and 6% other NGLs). First half 2021 sales volumes are expected to average between 74,000 Boe/d and 76,000 Boe/d (57% shale gas and conventional natural gas combined, 37 % light and medium crude oil, tight oil and condensate combined and 6% other NGLs). Second half 2021 sales volumes are expected to increase to average between 80,000 Boe/d and 84,000 Boe/d (54% shale gas and conventional natural gas combined, 40% light and medium crude oil, tight oil and condensate combined and 6% other NGLs).

ADVISORIES

Forward-looking Information

Certain statements in this document constitute forward-looking information under applicable securities legislation. Forward-looking information typically contains statements with words such as "anticipate", "believe", "estimate", "will", "expect", "plan", "schedule", "intend", "propose", or similar words suggesting future outcomes or an outlook. Forward-looking information in this document includes, but is not limited to:

- planned capital expenditures for 2021 and the timing and allocation thereof;
- forecast sales volumes for 2021 and certain periods within 2021;
- the expectation that production will materially grow in the Grande Prairie Region in 2021;
- forecast free cash flow in 2021;
- planned exploration, development and production activities, including the expected timing of completing and bringing new wells on production;
- planned abandonment and reclamation expenditures and activities in 2021 and anticipated funding under the ASRP;
- planned facility outages and turnarounds;
- forecast decreases in per unit operating costs at Karr;
- the potential to realize further reductions in future development costs if actual DCET costs continue to be lower than the costs used by the Company's independent third-party reserves evaluator in 2020; and
- expected GHG reductions associated with controller upgrades.

Such forward-looking information is based on a number of assumptions which may prove to be incorrect. Assumptions have been made with respect to the following matters, in addition to any other assumptions identified in this document:

- future natural gas and liquids prices and the potential impact of the COVID-19 pandemic thereon;
- the likely impact of the COVID-19 pandemic on operations;
- the ability to realize expected cost savings;
- royalty rates, taxes and capital, operating, general & administrative and other costs;
- foreign currency exchange rates and interest rates;
- general business, economic and market conditions;
- the ability of Paramount to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of Paramount to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost to carry out its activities;
- the ability of Paramount to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms and the capacity and reliability of facilities;
- the ability of Paramount to market its natural gas and liquids successfully to current and new customers;
- the ability of Paramount and its industry partners to obtain drilling success (including in respect of anticipated production volumes, reserves additions, liquids yields and resource recoveries) and operational improvements, efficiencies and results consistent with expectations;
- the timely receipt of required governmental and regulatory approvals;
- the receipt of benefits under government programs;
- the application of regulatory requirements respecting abandonment and reclamation; and
- anticipated timelines and budgets being met in respect of drilling programs and other operations (including well completions and tie-ins, the construction, commissioning and start-up of new and expanded facilities, including third-party facilities, and facility turnarounds and maintenance).

Statements relating to reserves are also deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future.

Although Paramount believes that the expectations reflected in such forward-looking information are reasonable based on the information available at the time of this document, undue reliance should not be placed on the forward-looking information as Paramount can give no assurance that such expectations will prove to be correct. Forward-looking information is based on expectations, estimates and projections that involve a number of risks and uncertainties which could cause actual results to differ materially from those anticipated by Paramount and described in the forward-looking information. The material risks and uncertainties include, but are not limited to:

- fluctuations in natural gas and liquids prices, including in relation to the impact of the COVID-19 pandemic;
- changes in capital spending plans and planned exploration and development activities;
- changes in foreign currency exchange rates and interest rates;

- the uncertainty of estimates and projections relating to future revenue, free cash flow, production, reserve additions, liquids yields (including condensate to natural gas ratios), resource recoveries, royalty rates, taxes and costs and expenses;
- the ability to secure adequate product processing, transportation, fractionation, and storage capacity on acceptable terms;
- operational risks in exploring for, developing, producing and transporting natural gas and liquids, including the risk of spills, leaks or blowouts;
- the ability to obtain equipment, services, supplies and personnel in a timely manner and at an acceptable cost;
- potential disruptions, delays or unexpected technical or other difficulties in designing, developing, expanding or operating new, expanded or existing facilities (including third-party facilities);
- processing, pipeline, and fractionation infrastructure outages, disruptions and constraints;
- risks and uncertainties involving the geology of oil and gas deposits;
- the uncertainty of reserves estimates;
- general business, economic and market conditions;
- the ability to generate sufficient cash flow from operations and obtain financing to fund planned exploration, development and operational activities and meet current and future commitments and obligations (including product processing, transportation, fractionation and similar commitments and obligations);
- changes in, or in the interpretation of, laws, regulations or policies (including environmental laws);
- the ability to obtain required governmental or regulatory approvals in a timely manner, and to obtain and maintain leases and licenses;
- the effects of weather and other factors including wildlife and environmental restrictions which affect field operations and access;
- the timing and cost of future abandonment and reclamation obligations and potential liabilities for environmental damage and contamination;
- uncertainties regarding aboriginal claims and in maintaining relationships with local populations and other stakeholders;
- the outcome of existing and potential lawsuits, insurance claims, regulatory actions, audits and assessments; and
- other risks and uncertainties described elsewhere in this document and in Paramount's other filings with Canadian securities authorities.

The foregoing list of risks is not exhaustive. For more information relating to risks, see the sections titled "*Risk Factors*" in Paramount's annual information form for the year ended December 31, 2020, which is available on SEDAR at www.sedar.com. The forward-looking information contained in this document is made as of the date hereof and, except as required by applicable securities law, Paramount undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise.

Non-GAAP Financial Measures

In this document, "Adjusted funds flow", "Netback", "Free cash flow", "Net Debt" and "Total Capital Expenditure", together the "Non-GAAP financial measures", are used and do not have any standardized meanings as prescribed by International Financial Reporting Standards. Certain comparative figures have been reclassified to conform to the current years' presentation.

"Adjusted funds flow" refers to cash from operating activities before net changes in non-cash working capital, geological and geophysical expenses, asset retirement obligation settlements, closure costs, transaction and reorganization costs, provision and other and dispute settlements. Adjusted funds flow is used to assist management and investors in measuring the Company's ability to fund capital programs and meet financial obligations, including the settlement of asset retirement obligations. Asset retirement obligation settlements are excluded from the calculation of adjusted funds flow because such expenditures are not directly linked to the revenue generating activities of the Company. Paramount manages the timing of expenditures related to asset retirement obligation settlements in accordance with regulatory requirements and its overall approach to managing its asset retirement obligations and, as a result, amounts incurred may vary significantly from period to period. Adjusted funds flow is not intended to represent cash from operating activities, net loss or any other GAAP measure and should not be construed as being an alternative to, or more meaningful than, cash flow from operating activities as determined in accordance with IFRS. The following are the calculations of adjusted funds flow from the nearest GAAP measure for the three months and twelve months ended December 31, 2020 and December 31, 2019:

Year ended December 31	2020 (MM$)	2019 (MM$)
Cash from operating activities	**80.9**	**255.7**
Change in non-cash working capital	17.9	(15.9)
Geological and geophysical expenses	8.5	11.0
Asset retirement obligations settled	35.0	29.4
Closure costs	—	14.0
Transaction and reorganization costs	3.0	2.3
Provision and other	4.7	2.5
Adjusted funds flow	**150.0**	**299.0**

Three months ended December 31	2020 (MM$)	2019 (MM$)
Cash from operating activities	**53.2**	**70.5**
Change in non-cash working capital	12.5	(8.0)
Geological and geophysical expenses	2.1	3.5
Asset retirement obligations settled	0.1	18.0
Closure costs	—	4.7
Transaction and reorganization costs	—	2.3
Dispute settlements	—	2.5
Adjusted funds flow	**67.9**	**93.5**

"Free cash flow" refers to adjusted funds flow less total capital expenditures and asset retirement obligation settlements. Free cash flow is used by management and investors to assess the amount of internally generated cash available to repay debt, reinvest in the business or return to shareholders. The following is the calculation of free cash flow from the nearest GAAP measure for the three months ended December 31, 2020:

Three months ended December 31	2020 (MM$)
Cash from operating activities	**53.2**
Change in non-cash working capital	12.5
Geological and geophysical expenses	2.1
Asset retirement obligations settled	0.1
Closure costs	—
Transaction and reorganization costs	—
Provision and other	—
Adjusted funds flow	**67.9**
Total capital expenditures	(65.1)
Asset retirement obligation settled	(0.1)
Free cash flow	**2.7**

"Netback" equals petroleum and natural gas sales less royalties, operating expense and transportation and NGLs processing costs. Netback is commonly used by management and investors to compare the results of the Company's oil and gas operations between periods. Refer to the table under the heading "Financial and Operating Results" for the calculation thereof.

"Net Debt" is a measure of the Company's overall debt position after adjusting for certain working capital and other amounts and is used by management to assess the Company's overall leverage position. Refer to the Liquidity and Capital Resources section of the Company's Management's Discussion and Analysis for the year ended December 31, 2020 (the "MD&A") for the calculation of Net Debt.

"Total capital expenditures" refers to the Company's property, plant and equipment and exploration expenditures. Refer to the Property, Plant and Equipment and Exploration Expenditures section of the MD&A for the calculation thereof.

Non-GAAP financial measures should not be considered in isolation or construed as alternatives to their most directly comparable measure calculated in accordance with GAAP, or other measures of financial performance calculated in accordance with GAAP. The Non-GAAP financial measures are unlikely to be comparable to similar measures presented by other issuers.

Reserves Data

Reserves data set forth in this document is based upon an evaluation of the Company's reserves prepared by McDaniel & Associates Consultants Ltd. ("McDaniel") dated March 2, 2021 and effective December 31, 2020 (the "McDaniel Report"). The price forecast used in the McDaniel Report is an average of the January 1, 2021 price forecasts for McDaniel and GLJ Petroleum Consultants Ltd. and the December 31, 2020 price forecast of Sproule Associates Ltd. The estimates of reserves contained in the McDaniel Report and referenced in this document are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates contained in the McDaniel Report and referenced in this document. There is no assurance that the forecast prices and costs assumptions used in the McDaniel Report will be attained, and variances could be material. Estimated future net revenue does not represent fair market value. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. Readers should refer to the Company's annual information form for the year ended December 31, 2020, which is available on SEDAR at www.sedar.com, for a complete description of the McDaniel Report (including reserves by specific product type of shale gas, conventional natural gas, NGLs, tight oil and light and medium crude oil) and the material assumptions, limitations and risk factors pertaining thereto.

Oil and Gas Measures and Definitions

Abbreviations

Liquids	
Bbl	Barrels
Bbl/d	Barrels per day
MBbl	Thousands of barrels
NGLs	Natural gas liquids
Condensate	Pentane and heavier hydrocarbons

Oil Equivalent	
Boe	Barrels of oil equivalent
MBoe	Thousands of barrels of oil equivalent
MMBoe	Millions of barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day

Natural Gas	
GJ	Gigajoules
GJ/d	Gigajoules per day
Mcf	Thousands of cubic feet
MMcf	Millions of cubic feet
MMcf/d	Millions of cubic feet per day
AECO	AECO-C reference price
WTI	West Texas Intermediate

This document contains disclosures expressed as "Boe", "$/Boe", "MBoe", "MMBoe" and "Boe/d". Natural gas equivalency volumes have been derived using the ratio of six thousand cubic feet of natural gas to one barrel of oil when converting natural gas to Boe. Equivalency measures may be misleading, particularly if used in isolation. A conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well head. For the year ended December 31, 2020, the value ratio between crude oil and natural gas was approximately 21:1. This value ratio is significantly different from the energy equivalency ratio of 6:1. Using a 6:1 ratio would be misleading as an indication of value.

This document contains metrics commonly used in the oil and natural gas industry. Each of these metrics is determined by the Company as set out below or elsewhere in this document. The metrics are “CGR”, "recycle ratio", "reserves replacement ratio" and "finding and development costs". These metrics do not have standardized meanings and may not be comparable to similar measures presented by other companies. As such, they should not be used to make comparisons. Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare the Company's performance over time; however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the performance in previous periods and therefore should not be unduly relied upon.

“CGR” means condensate to gas ratio and is calculated by dividing wellhead raw liquids volumes by wellhead raw natural gas volumes.

“Recycle ratio” is calculated by dividing netback per Boe by applicable finding and development costs. This metric is utilized by management and investors to monitor reserve addition efficiencies relative to the netbacks achieved from such reserve additions.

“Reserves replacement ratio” is calculated by dividing: (i) the aggregate changes in reserves from the prior year from extensions/improved recovery, technical revisions and economic factors, by (ii) the aggregate production during the year. Reserves replacement ratio is a measure commonly used by management and investors to assess the rate at which reserves depleted by production are being replaced by reserves added through operations.

“Finding and development costs” are calculated by dividing: (i) total capital expenditures for the period (excluding corporate expenditures, land and property acquisitions and, in 2018 and 2019, expenditures of $35.9 million and $45.5 million associated with the expansion of the Karr 6-18 facility that was disposed of in 2019) by (ii) the net changes in reserves from the prior year from extensions/improved recovery, technical revisions and economic factors. Finding and development costs are a measure commonly used by management and investors to assess the relationship between capital invested in oil and gas exploration and development projects and reserve additions associated with such projects.

Additional information respecting the Company’s oil and gas properties and operations is provided in the Company’s annual information form for the year ended December 31, 2020 which is available on SEDAR at www.sedar.com.

CORPORATE INFORMATION

EXECUTIVE OFFICERS

J. H. T. Riddell
President and Chief Executive Officer and Chairman

P. R. Kinvig
Chief Financial Officer

B. K. Lee
Executive Vice President, Finance

E. M. Shier
General Counsel and Vice President, Land

D. B. Reid
Executive Vice President, Operations

R. R. Sousa
Executive Vice President, Corporate Development and Planning

J. B. Williams
Executive Vice President, Kaybob Region

DIRECTORS

J. H. T. Riddell (2)
President and Chief Executive Officer
and Chairman
Paramount Resources Ltd.
Calgary, Alberta

J. G. M. Bell (1) (3) (4)
President and Chief Executive Officer
Founders Advantage Capital Corp.
Calgary, Alberta

W. A. Gobert (3) (4) (5)
Independent Businessman
Calgary, Alberta

J. C. Gorman (1) (4) (5)
Independent Businessman
Calgary, Alberta

D. Jungé C.F.A. (2) (4)
Independent Businessman
Bryn Athyn, Pennsylvania

R. M. MacDonald (1) (3) (4)
Independent Businessman
Oakville, Ontario

R. K. MacLeod (2) (4) (5)
Independent Businessman
Calgary, Alberta

S. L. Riddell Rose
President and Chief Executive Officer
Perpetual Energy Inc.
Calgary, Alberta

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

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BANKS

Bank of Montreal

The Bank of Nova Scotia

HSBC Bank Canada

Royal Bank of Canada

Export Development Canada

Canadian Imperial Bank of Commerce

National Bank of Canada

ATB Financial

The Toronto-Dominion Bank

RESERVES EVALUATORS

McDaniel & Associates Consultants Ltd.
Calgary, Alberta

AUDITORS

Ernst & Young LLP
Calgary, Alberta

STOCK EXCHANGE LISTING

The Toronto Stock Exchange
(“POU”)