Osum Oil Sands Corp.

2019 Annual Report to Shareholders

Dated March 26, 2020

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Review and Outlook

2019 Annual Review

Osum transformed its business in 2019. With the Orion Phase 2BC expansion ramping up earlier than forecast and the Phase 1 wells exceeding expectations, Osum increased its average year-over-year production by 69% from 11,082 bbl/d to 18,750 bbl/d, including a record fourth quarter average of 20,539 bbl/d. The higher production and corresponding operational efficiencies, combined with improved bitumen pricing, led to a field netback of $228.1 million in the year, more than five times higher than the field netback in 2018.

The improved bitumen pricing largely reflected measures taken by the Government of Alberta to address the historically wide Canadian oil price differentials experienced in late 2018. On December 2, 2018 and effective January 1, 2019, the Province announced a curtailment of oil production for its largest oil producers, including Osum, for 2019 but which was later amended and extended to the end of 2020. The positive impact of the subsequent decrease in oil price differentials greatly exceeded the negative impact of Osum's forgone production. However, that net benefit was tempered by $54.1 million in net losses from the Company's hedging program that had locked in wider differentials in anticipation of continued price weakness through the first half of the year, leading to a netback after hedging of $174.0 million.

Highlighting the significant free cash flow generated during the year, Osum's term debt net of unrestricted cash was halved over the period from $221.6 million at December 31, 2018 to $108.8 million at the end of 2019.

Other points of note for 2019 included:

- Ramp-up of Orion Phase 2BC during curtailment: Half of the 18 new horizontal SAGD well pairs were on production in late 2018 when the curtailment rules were announced. Curtailment orders set Osum's production limit at about 12,700 bbl/d in January and just under 17,000 bbl/d for February through September 2019. These levels were below the production capability of the Orion facility and wells and potentially threatened long-term resource recovery. In order to maximize production during those months while complying with the curtailment rules, Osum managed the timing of bringing wells on stream, the levels of steam injection and bitumen production, and purchased curtailment allotments from third parties. Based on amendments to the curtailment rules, Osum was not subject to curtailment during the fourth quarter. Despite the constraints, the resulting full-year average production of 18,750 bbl/d was above the facility's forecast capability of 18,000 bbl/d, which had not been projected to be reached until the third quarter of 2019.

- Curtailment allotment purchases: During 2019, the Company incurred costs totaling $4.5 million to purchase curtailment allotments from third parties in order to produce at levels above its initial curtailment limits. Given strong bitumen pricing during the year and the low marginal cost to produce the incremental barrels, the purchases were economic.

- Lower WTI more than offset by tighter heavy oil differential: The Company's average realized bitumen price in 2019 of $48.83/bbl was up $23.02/bbl or 89% from 2018. The increase in the average bitumen price reflected the significant tightening of the WTI-CLB price differential to an average of US$12.93/bbl in 2019, less than half of the prior year's differential of US$27.21/bbl, owing mainly to the curtailment measures put in place by the Province. The positive impact, combined with a weaker average Canadian dollar in relation to the US dollar, was partially offset by the decrease in the average West Texas Intermediate ("WTI") oil price of US$7.73/bbl or 12% in 2019 to US$57.05/bbl, compared with US$64.78/bbl in the prior year.

- Higher unit royalties but lower royalty rate: Average unit royalties in 2019 were $3.62/bbl or 7.4% of blended bitumen sales after deducting product purchases and diluent and transportation costs, compared with $2.67/bbl or 10.3% in the prior year. The higher unit cost was due mainly to the higher bitumen price in 2019, but was partially offset by a lower crown royalty rate that decreased with a lower C$ WTI price. Total royalties more than doubled in 2019 to $24.8 million from $10.8 million in 2018, due largely to higher production and bitumen pricing.
- Lower unit operating costs: Following a 27% decrease in total unit operating costs from 2017 to 2018, Osum continued to drive down operating costs in 2019. Average total unit operating costs in 2019 of $11.23/bbl fell by 14% or $1.85/bbl from the prior year. Non-fuel unit operating costs decreased 18% or $1.91/bbl to $8.80/bbl, due primarily to fixed costs such as field staff and facility repairs and maintenance being spread across higher production. Fuel unit operating costs of $2.43/bbl in 2019 were similar to $2.37/bbl in 2018.
- Record netbacks: As a result of higher production, improved bitumen pricing, and lower unit operating costs, the field netback climbed to $228.1 million in 2019, more than five times higher than the $40.7 million in the prior year. The 2019 unit field netback was $33.33/bbl, compared with $10.06/bbl in 2018. However, gains in the field were partially mitigated by net hedging losses of $54.1 million or $7.91/bbl, resulting in a netback after hedging of $174.0 million or $25.42/bbl, compared with $48.7 million or $12.03/bbl in 2018. At December 31, 2019, the Company's net unrealized hedging liability was $16.0 million.
- Debt extension and reduction: During 2019, Osum completed an amendment with its lenders to extend the maturity date of 90.6% of the outstanding balance of its term loan by two years to July 31, 2022. The interest rate on the extended portion of the loan was increased and varies between LIBOR plus 7.5% and 9.5% per annum depending on the Company's debt to cash flow ratio. The remaining 9.4% of the loan continues to bear interest at LIBOR plus 5.5% per annum and will mature as scheduled on July 31, 2020. During 2019, Osum made mandatory and voluntary debt repayments at par totaling $38.6 million (US$29.2 million), reducing the outstanding term loan balance to $223.3 million (US$171.9 million) at December 31, 2019. Also during 2019, Osum extended the maturity date of its undrawn US$15 million revolving credit facility by two years to April 30, 2022.
- Stable overhead costs despite growth: Net general and administrative ("G&A") costs totaled $12.9 million in 2019, approximately the same as the prior year. However, on the strength of higher production, unit net G&A costs decreased by 40% to $1.89/bbl from $3.13/bbl.
- Low sustaining capital needs: Following the completion of Orion Phase 2BC in October 2018, capital expenditures in 2019 were $18.0 million, compared with $165.8 million in the prior year. The limited capital spending reflects the low production declines associated with SAGD projects.
- Positioned for further expansion: With significant free cash generation, Osum is well positioned to further increase production at Orion with small debottlenecking projects once curtailment is lifted and it is economic to do so. At December 31, 2019, cash on hand was $125.6 million and net working capital, excluding the current portions of net unrealized hedging assets and deferred consideration, but including $42.8 million of term loan repayments that will be made in March and July, totaled $82.1 million. The Company's undrawn US$15.0 million revolving credit facility serves as an additional source of liquidity.

Outlook

The beginning of 2020 initially appeared promising for the Canadian energy industry with a more balanced supply and demand outlook and stability in world oil prices. However, conditions began to deteriorate rapidly in mid-March with the global spread of a novel coronavirus, COVID-19, and the failure of OPEC and OPEC+ to reach an agreement to restrict supply in the face of slowing economic activity. The combination of the two resulted in a quick and severe drop in world oil prices to levels not seen for close to two decades.

The work Osum has done over the last few years to grow its production, lower its cost structure, reduce and extend its debt, and hedge commodity prices has positioned the Company to navigate the challenges of the current market environment. However, given that at present prices are below the level required to break even in the field, Osum has taken further steps to protect its balance sheet, preserve liquidity, and maintain financial flexibility. Notably, the Company has deferred the plant turnaround at Orion, originally scheduled for May and June of 2020, until at least the fall of this year. The move will not only reduce near-term capital spending but also will avoid having a large number of staff and contractors working in close proximity to one another at a time when maintaining proper social distance is of critical importance. In addition, planned capital expenditures at Orion have been rationalized to include only those necessary to maintain the safe and efficient operation of the wells and central processing facility. Debottlenecking and production growth projects have been deferred until prices recover. In the interim, Osum's existing commodity hedges which have locked in higher prices on approximately 50% of the Company's forecast production, net of maximum royalties, will provide some financial cover for the balance of the year. At March 20, 2020, the mark-to-market value of those hedges was a net asset of $70.2 million.

With production having exceeded 20,000 bbl/d during the fourth quarter of 2019, Osum again became subject to the Province's curtailment rules beginning in March 2020, with a monthly limit of just above 20,000 bbl/d. While that limit is close to Orion's production capability, given the collapse in oil prices, the Company is adjusting its operations, including the level of production, to maximize cash flow. As a result, until market conditions improve, volumes at Orion are likely to be below the level allowed by the curtailment rules.

Response to COVID-19 and Postponement of Annual General Meeting

Osum recognizes the very serious threat to public health posed by the novel coronavirus and is committed to ensuring its organization responds in a way that prioritizes the safety of its employees and the broader community. The Company is following government guidelines and has implemented internal measures that address preventative hygiene, social distancing, self-monitoring and travel. In addition, Osum has activated its emergency response plan and formed a COVID-19 Preparedness and Response team that provides regular updates and current information on the pandemic to staff. To date, there have been no impacts to production or personnel levels.

The Company will continue to take all necessary actions to protect the health and safety of its staff and to mitigate the risks to business continuity. As part of this, Osum is postponing its annual general meeting of shareholders until a later date to be determined. Once set, a notice of meeting, proxy, and information circular will be sent to shareholders.

Management’s Discussion and Analysis

The following management’s discussion and analysis (“MD&A”) of financial results is dated March 26, 2020 and is to be read in conjunction with the accompanying audited annual consolidated financial statements and related notes for the year ended December 31, 2019 of Osum Oil Sands Corp. (“Osum” or "the Company”). The consolidated financial statements for the year ended December 31, 2019 have been prepared in accordance with International Financial Reporting Standards ("IFRS"). All amounts are expressed in thousands of Canadian dollars ("C$") unless otherwise specified.

Nature of Business

Osum is a private company principally focused on the development and operation of in-situ bitumen properties in Alberta, Canada. Since inception, Osum has concentrated its efforts on: acquiring prospective oil sands properties; developing those properties into projects; and securing the financial and human resources required to construct and operate those projects.

The Company's wholly-owned Orion oil sands project (“Orion”) is a producing in-situ project in the Cold Lake oil sands area of Alberta and represents the Company’s only commercial production. The Company also has a 100% interest in five other potential development projects: Taiga (also in Cold Lake), Sepiko Kesik ("SK"), Saleski West, Liege and Portage, as well as a 40% non-operated interest in the Saleski joint venture.

Non-IFRS Financial Measures

This document includes references to financial measures commonly used in the oil and gas industry, such as adjusted working capital, netback, adjusted netback and funds flow. These financial measures are not defined by IFRS as issued by the International Accounting Standards Board ("IASB") and therefore are referred to as non-IFRS measures. The non-IFRS measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-IFRS measures to help evaluate its performance against prior periods on a comparable basis.

Descriptions of these non-IFRS measures, a discussion of their usefulness and reconciliations to comparable IFRS measures are provided below.

<u>Adjusted working capital</u>

In describing its liquidity and financial resources, the Company makes reference to adjusted working capital, a measure that is not based on IFRS.

Adjusted working capital is a liquidity measure used by management to assess the Company's ability to settle its current obligations with liquid assets. Adjusted working capital is equal to working capital, an IFRS measure, adjusted to exclude the current portions of financial risk management contract assets and liabilities and deferred consideration. Deferred consideration is excluded from adjusted working capital because it is not cash-settled, while risk management assets and liabilities are excluded as they are fair value estimates of future gains and losses that are subject to a high degree of volatility prior to ultimate settlement.

A reconciliation of adjusted working capital to working capital, an IFRS measure, is provided below:

As at December 31,	2019	2018
Working capital	64,701	76,823
Add (deduct):		
Current portion of deferred consideration	1,420	1,156
Current portion of net financial risk management liability (asset)	16,012	(22,008)
Adjusted working capital	82,133	55,971

Netback and adjusted netback

The Company reports netback and adjusted netback measures to evaluate operating efficiency and its ability to fund corporate expenses, sustaining capital and future growth. Netback is calculated by deducting the related diluent, transportation, product and curtailment allotment purchases, royalties and field operating costs from petroleum sales. Adjusted netback is calculated by adjusting the netback to include realized gains and losses on financial risk management contracts. Each netback on a per-unit basis is calculated by dividing by bitumen production. Though widely used in the oil and gas industry, these or similar measures do not have standardized meanings prescribed by IFRS and therefore may not be comparable to similar measures used by other companies.

A reconciliation of each measure to net and comprehensive income, an IFRS measure, is provided below:

For the year ended December 31,	2019	2018
Net and comprehensive income	33,595	135,553
Add (deduct):		
Depletion and depreciation	58,125	36,191
Reversal of impairment	—	(135,525)
Net finance costs	36,576	26,192
General and administrative expenses	12,940	12,660
Deferred income tax recovery	(6,374)	(22,452)
Share-based compensation expense	10,963	6,344
Accretion	873	887
Unrealized foreign exchange loss (gain)	(12,427)	21,595
Net loss (gain) on risk financial management contracts	96,594	(34,758)
Deferred consideration	(2,787)	(5,991)
Netback	228,078	40,696
Realized gain (loss) on financial risk management contracts	(54,114)	7,969
Adjusted netback	173,964	48,665

Funds flow

The Company reports funds flow as a key measure indicative of the funds available for re-investment or to maintain the operations of the Company. Funds flow is not intended to represent operating profit (loss), nor should it be viewed as an alternative to cash flows from operating activities, net income (loss) or other measures of financial performance calculated in accordance with IFRS. Funds flow is calculated as cash flows from operating activities, an IFRS measure, adjusted to exclude changes in non-cash operating working capital.

The Company’s funds flow is reconciled to cash flows from operating activities, below:

For the year ended December 31,	2019	2018
Cash flows from operating activities	116,964	19,733
Add (deduct): Change in non-cash operating working capital	9,291	(4,514)
Funds flow	126,255	15,219

Bitumen Reserves

The Company's bitumen reserves related to its Orion and Taiga projects were evaluated by independent third-party engineers, GLJ Petroleum Consultants Ltd. ("GLJ") in their report effective December 31, 2019. Bitumen reserves estimates were prepared in accordance with definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook.

Future net revenue arising from the anticipated development and production of reserves, net of the associated royalties (inclusive of the gross overriding royalty ("GORR")), was estimated by GLJ using forecast prices, operating costs, development costs and abandonment and reclamation costs, but before corporate overhead or other indirect costs, including interest and income taxes. Future net revenue disclosed does not represent fair market value. Also, estimations of reserves and future net revenue discussed in this section constitute forward looking information. See "Forward-Looking Statements" in this MD&A.

The following table compares bitumen reserves and the net present value of future net revenue at a 10% discount rate as at December 31, 2019 and December 31, 2018:

	Bitumen Reserves – Gross (Mbbl)			Net Present Value of Future Net Revenue at 10% – Before Taxes ($ millions)		
As at December 31,	2019 (1)	2018 (2)	%	2019 (1)	2018 (2)	%
Total proved (3)	141,628	141,634	— %	1,593	1,572	1%
Total proved plus probable (3)(4)	614,540	541,893	13 %	3,287	2,815	17%

(1) GLJ reserve estimates based on forecast prices and costs as of January 1, 2020, effective December 31, 2019.

(2) GLJ reserve estimates based on forecast prices and costs as of January 1, 2019, effective December 31, 2018.

(3) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(4) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Estimated proved bitumen reserves ("1P reserves") assigned to the Orion project were 141,628 thousand barrels (Mbbl) at December 31, 2019, relatively unchanged from 141,634 Mbbl at December 31, 2018. Additional 1P reserves assigned due to higher forecast recovery factors supported by Phase 1 production performance were offset by 2019 production of 6,844 Mbbl.

The ten percent present value of estimated future net revenue ("PV10") of 1P reserves was $1,593 million at December 31, 2019, an increase of 1% from December 31, 2018. The benefit of lower forecast future development and operating costs following the completion of Orion Phase 2BC was largely offset by the negative impact of lower forecast bitumen pricing.

Estimated proved plus probable bitumen reserves ("2P reserves") assigned to both the Orion and Taiga projects increased by 72,647 Mbbl or 13% to 614,540 Mbbl at December 31, 2019. The increase in 2P reserves largely reflected an increase in reserves assigned to Taiga based on the performance of analogue projects.

The PV10 of 2P reserves of $3,287 million at December 31, 2019 was an increase of $472 million or 17% from $2,815 million at December 31, 2018, largely due to higher 2P reserves, lower forecast capital and operating costs at Taiga and lower forecast natural gas pricing, partially offset by lower forecast bitumen pricing.

The following table displays gross bitumen reserves and bitumen reserves net of forecast royalties (inclusive of the GORR), along with the present values of estimated future net revenue using a range of discount rates at December 31, 2019:

	Bitumen Reserves [1] – (Mbbl)		Net Present Value of Future Net Revenue – Before Taxes ($millions) Forecast Prices and Costs				
	Gross	Net	0%	5%	10%	15%	20%
Total proved [2] (1P)	141,628	104,786	3,481	2,267	1,593	1,195	945
Total proved plus probable [2][3] (2P)	614,540	474,953	18,217	6,535	3,287	1,993	1,347

(1) GLJ reserve estimates based on forecast prices and costs as of January 1, 2020, effective December 31, 2019.

(2) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(3) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

GLJ's pricing assumptions used in its December 31, 2019 evaluation are summarized below:

Year	Western Canadian Select (C$/bbl)	WTI at Cushing (US$/bbl)	Diluent (condensate) (C$/bbl)	AECO gas (C$/mmbtu)	Exchange rate (US$/C$)
2020	57.89	61.00	77.80	2.08	0.760
2021	61.04	63.00	79.22	2.35	0.770
2022	64.10	66.00	83.33	2.55	0.780
2023	66.67	68.00	86.54	2.65	0.780
2024	69.23	70.00	89.10	2.75	0.780
2025	71.79	72.00	91.67	2.85	0.780
2026	74.36	74.00	94.23	2.91	0.780
2027	76.68	75.81	96.55	2.97	0.780
2028	78.63	77.33	98.50	3.03	0.780
2029	80.62	78.88	100.49	3.09	0.780
Remainder	+2.0% per year	+2.0% per year	+2.0% per year	+2.0% per year	0.780

Financial and Operational Summary

For the years ended December 31,	2019	2018
Business Environment [1]		
West Texas Intermediate (WTI) – US$/bbl	57.05	64.78
Cold Lake Blend (CLB) – US$/bbl	44.12	37.57
Differential – WTI less CLB – US$/bbl	12.93	27.21
Differential – CLB % of WTI	22.7%	42.0%
Foreign exchange rate – C$/US$	1.3270	1.2964
CLB – $/bbl	58.55	48.71
AECO gas – $/mcf	1.66	1.46
Operational [1] [2]		
Bitumen production – bbl/d	18,750	11,082
Blended bitumen sales – bbl/d	25,543	15,359
Net bitumen revenue – $/bbl	48.83	25.81
Royalties – $/bbl	(3.62)	(2.67)
Non-fuel operating costs – $/bbl	(8.80)	(10.71)
Fuel operating costs – $/bbl	(2.43)	(2.37)
Curtailment allotment purchases – $/bbl	(0.65)	—
Netback [3] – $/bbl	33.33	10.06
Realized net gain (loss) on financial risk management contracts – $/bbl	(7.91)	1.97
Adjusted netback [3] – $/bbl	25.42	12.03
Financial		
Cash flows from operating activities	116,964	19,733
Funds flow [4]	126,255	15,219
Net and comprehensive income	33,595	135,553
Netback [3]	228,078	40,696
Realized net gain (loss) on risk management contracts	(54,114)	7,969
Adjusted netback [3]	173,964	48,665
Net income per share (basic) – $	0.26	1.03
Capital investment [5]	18,042	165,756
General and administrative expenses (net) [6]	12,940	12,660
Cash and cash equivalents [7]	125,576	66,555
Working capital	64,701	76,823
Adjusted working capital [8]	82,133	55,971
Outstanding principal – long-term debt [9]	180,475	271,421
Shareholders' equity	504,809	468,102
Weighted average common shares outstanding	131,626	131,009

See footnotes on the next page.

(1) Business environment and operational metrics are averages for the year.
(2) Dollar per barrel metrics are calculated based on bitumen production volumes. Year-over-year per barrel metrics may be affected by differences between the timing of bitumen production and blended bitumen sales.
(3) Netback is calculated by deducting the related diluent, transportation, product and curtailment allotment purchases, royalty and field operating costs from petroleum sales. Adjusted netback is calculated by adjusting the netback to include realized gains and losses on financial risk management contracts.
(4) Funds flow is calculated as cash flows from operating activities before changes in non-cash operating working capital, which is presented on the consolidated statement of cash flows.
(5) Capital investment includes capitalized general and administrative expenses but excludes capitalized stock-based compensation expense.
(6) General and administrative expenses (net) is calculated after reductions for capitalized salaries and benefits, onerous lease payments and exploration expenses.
(7) Cash and cash equivalents include restricted cash.
(8) Adjusted working capital is calculated as working capital adjusted to exclude the current portions of risk management contracts, which are fair value estimates of unrealized gains and losses and are subject to a high degree of volatility prior to ultimate settlement, and deferred consideration, which does not impact cash.
(9) Outstanding principal of long-term debt consists of the non-current portions of the outstanding principal balances of the term loans and any amounts outstanding under the revolving loan, translated to Canadian dollars at the period-end foreign exchange rate and presented before unamortized transaction costs.

Results of Operations

Netback and adjusted netback

For the years ended December 31,	2019		2018	
Production – bbl/d		18,750		11,082
Blended bitumen sales – bbl/d		25,543		15,359
	($000s)	$/bbl	($000s)	$/bbl
Petroleum sales	562,450		246,254	
Diluent and transportation costs	196,125		136,920	
Product purchases	32,115		4,944	
Net bitumen revenue	334,210	48.83	104,390	25.81
Royalties	(24,808)	(3.62)	(10,783)	(2.67)
Operating costs – non-fuel	(60,248)	(8.80)	(43,333)	(10.71)
Operating costs – fuel	(16,608)	(2.43)	(9,578)	(2.37)
Curtailment allotment purchases	(4,468)	(0.65)	—	—
Netback	228,078	33.33	40,696	10.06
Realized gain (loss) on financial risk management contracts	(54,114)	(7.91)	7,969	1.97
Adjusted netback	173,964	25.42	48,665	12.03

Production

Provincial curtailment orders set Osum's production limit at about 12,700 bbl/d in January 2019 and just under 17,000 bbl/d for February through September, which levels were below the productive capability of the Orion facility and wells and potentially threatened long-term resource recovery. In order to maximize production during those months while complying with the curtailment rules, Osum managed the timing of bringing wells on stream, the levels of steam injection and bitumen production and purchased curtailment allotments from third parties. Based on amendments to the curtailment rules, Osum was not subject to curtailment during the fourth quarter. Despite the constraints, the resulting full-year average production of 18,750 bbl/d for the year ended December 31, 2019 was 69% higher than the 2018 average of 11,082 bbl/d and above the original forecast for the facility of 18,000 bbl/d, which had not been expected to be reached until the third quarter of 2019.

Petroleum sales

Bitumen produced at Orion is mixed with purchased diluent and marketed as a heavy crude oil blend known as Cold Lake Blend ("CLB"). CLB is priced in US dollars ("US$") and generally trades at a discount to the price of West Texas Intermediate crude oil ("WTI"). As a result, the price received by the Company for its blended bitumen is a function of a number of factors, including the WTI price, the size of the differential between WTI and CLB, the US$/C$ exchange rate, and the access to and cost of transportation to ship the blended bitumen to market.

In addition to sales of blended bitumen, petroleum sales include revenue from sales of purchased diluent in excess of the Company's blending requirements.

For the years ended December 31,	2019	2018
Blended bitumen sales	547,257	241,956
Diluent sales	15,193	4,298
Petroleum sales	562,450	246,254

For the year ended December 31, 2019, blended bitumen sales more than doubled to $547,257, mainly due to a 66% increase in blended bitumen sales volumes to an average of 25,543 bbl/d from 15,359 bbl/d in the previous year and a 20% year-over-year increase in the average C$ CLB index price. Sales of diluent in excess of blending requirements increased to $15,193 in 2019 from $4,298 in the prior year, largely due to a lower blending ratio during some months of 2019 than was originally forecast.

Diluent and transportation costs

Condensate is a diluent that is purchased and added to produced bitumen to create a less viscous blended stream capable of being transported by pipeline. Historically, the price of condensate has been closely tied to the price of WTI.

For the year ended December 31, 2019, diluent and transportation costs were $196,125, compared with $136,920 in the prior year. The increase of $59,205 or 43% was mainly the result of a 59% increase in condensate usage, reflective of higher daily bitumen production, partially offset by lower blending requirements due to higher quality condensate receipts and a decrease in the price of condensate in line with the 10% average decrease in C$ WTI. Higher transportation costs consistent with the increase in blended bitumen sales volumes also contributed to the increase from the prior year.

Product purchases

From time to time, the Company purchases diluent for blending that later proves to be in excess of its requirements and blended bitumen to meet contractual sales commitments.

For the years ended December 31,	2019	2018
Blended bitumen purchases	16,922	646
Diluent purchases	15,193	4,298
Product purchases	32,115	4,944

For the year ended December 31, 2019, total product purchases were $32,115, compared with $4,944 in the prior year. The increase in blended bitumen purchases was largely due to a brief unplanned pipeline outage in 2019 that forced the Company to alter deliveries between the Hardisty and Edmonton sales points, while the increase in diluent purchases was mainly the result of a lower blending ratio during some months of 2019 than was originally forecast.

Royalties

A portion of the Company’s royalty expense is based on price-sensitive royalty rates set by the Government of Alberta. As well, the applicable royalty rate changes depending on whether a project is pre-payout or post-payout, with payout being defined as the point in time when a project has generated sufficient net revenues to recover its cumulative costs and a rate of return. The Company's operating property, Orion, is currently pre-payout. The royalty rate applicable to pre-payout oil sands operations starts at 1% of net bitumen revenue and increases proportionately for every dollar that WTI in C$ is priced above $55 per barrel, to a maximum of 9% when the price is $120 per barrel or higher.

In addition to crown royalties, the Company's royalties include a GORR of 4% of calculated net bitumen revenue.

For the year ended December 31, 2019, total royalties were $24,808, translating to an average royalty rate of 7.4%, compared with a royalty rate of 10.3% for the year ended December 31, 2018.

For the year ended December 31, 2019, crown royalties to the Government of Alberta were $11,454 or 3.4% of net bitumen revenue, compared with $5,950 or 5.7% in the prior year. The decrease in the provincial royalty rate resulted from a lower average C$ WTI price.

For the year ended December 31, 2019, gross overriding royalties were $13,354 or 4.0% of net bitumen revenue, compared with $4,883 or 4.6% in the prior year. The implied royalty rate in 2018 was higher than the 4.0% GORR as in November and December 2018 net bitumen revenue was negative and no royalties were paid.

Operating expenses

For the year ended December 31, 2019, non-fuel operating costs were $60,248 or $8.80/bbl, compared with $43,333 or $10.71/bbl in the prior year, an increase of 39% overall but a 18% decrease on a per barrel basis. The decrease in unit costs was primarily due to fixed costs such as field staff and facility repairs and maintenance being spread across higher production.

For the year ended December 31, 2019, fuel operating costs were $16,608 or $2.43/bbl, compared with $9,578 or $2.37/bbl in the prior year, an increase of 73% overall and 3% on a per barrel basis. The year-over-year increase in overall costs was mainly due to a 39% increase in the volume of steam injected and an increase in the average AECO gas price of 14%.

Curtailment allotment purchases

During the year ended December 31, 2019, the Company incurred costs totaling $4,468 to purchase curtailment allotments from third parties in order to produce at levels above its initial curtailment limits. Given strong bitumen pricing during the year and the low marginal cost to produce the incremental barrels, the purchases were economic. Curtailment was not in effect during the prior year.

Realized gain (loss) on financial risk management contracts

Realized gains and losses reflected the value received due to changes in the C$ WTI oil price, the C$ WTI-WCS and WTI-Condensate price differentials and AECO gas price since the contracts were executed.

For the year ended December 31, 2019, the net realized loss on risk management contracts totaled $54,114 or $7.91/bbl, compared with a net realized gain of $7,969 or $1.97/bbl in 2018. The net realized loss in 2019 resulted mainly from the significant tightening of the WTI-WCS differential that occurred due to the implementation of oil curtailment in Alberta. Prior to the Province's announcement, the Company had locked in wider differentials in anticipation of price weakness through the first half of 2019.

Deferred consideration

In 2017, the Company sold a 4.0% GORR on net bitumen revenue from all current and future production from the Clearwater formation of its Orion property for cash proceeds.

Deferred consideration represents the portion of proceeds attributable to the upfront payment received for costs expected to be incurred by the Company in relation to future production of the royalty owner's 4.0% share of proved and probable reserves. Deferred consideration is recognized as these costs are incurred.

Deferred consideration revenue of $2,787 was recorded for the year ended December 31, 2019, compared with $5,991 in the prior year. The decrease from 2018 was largely due to the decrease in year-over-year capital spending, partially offset by higher crown royalties and operating costs.

Change in fair value of financial risk management contracts

For the year ended December 31, 2019, the Company recorded an unrealized loss on financial risk management contracts of $42,480, compared with a gain of $26,789 in the previous year.

The unrealized loss in 2019 and gain in 2018 reflected the net change in the value of the Company's financial risk management contracts due to the changes in the forward curves of the C$ WTI oil price, the WTI-WCS and WTI-Condensate price differentials and AECO gas price from the contract execution dates to the reporting dates, adjusted for contracts settled or entered into between the reporting dates.

Depletion and depreciation

The Company's producing oil sands property, Orion, is depleted on a unit of production basis based on independently estimated proved and probable reserves. For the year ended December 31, 2019, depletion and depreciation totaled $58,125, compared with $36,191 in the prior year. The average depletion rate for 2019 of $8.34/bbl at Orion was consistent with $8.81/bbl in the prior year.

Impairment (reversal of impairment)

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

During 2019 the Company observed a decline in the average long-term price forecasts of a number of reserve engineering firms. The Company considered the price forecast decline an indicator of impairment for its Taiga CGU and performed an impairment test at December 31, 2019.

The Company estimated the recoverable amount of its Taiga CGU based on fair value less costs of disposal calculations. The fair value of the CGU was estimated based on the present value of after-tax cash flows resulting from production from proved and probable reserves from 2020 to 2069 using assumptions consistent with those used by the Company's independent reserve evaluator, including capital and operating cost estimates, corporate tax rates, and a cost inflation factor of two percent, and using an after-tax discount rate of 12%. The following forward prices and foreign exchange rates were used to estimate the recoverable amount as at December 31, 2019:

Year	Western Canadian Select (C$/bbl)	WTI at Cushing (US$/bbl)	Diluent (condensate) (C$/bbl)	AECO gas (C$/mmbtu)	Exchange rate (US$/C$)
2020	56.66	60.25	74.21	2.05	0.760
2021	61.20	63.11	78.15	2.32	0.768
2022	63.08	66.02	80.48	2.60	0.784
2023	64.92	67.64	82.77	2.74	0.789
2024	66.54	69.16	84.66	2.82	0.789
2025	68.16	70.69	86.56	2.91	0.789
2026	69.80	72.25	88.49	2.97	0.789
2027	71.41	73.77	90.40	3.03	0.789
2028	72.94	75.25	92.22	3.10	0.789
Remainder	+2.0% per year	+2.0% per year	+2.0% per year	+2.0% per year	0.789

Source: Average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule Associates and Deloitte Research Evaluation & Advisory price forecasts, effective January 1, 2020.

Based on the calculations performed, the estimated recoverable amount of the Taiga CGU exceeded its carrying value and no impairment was recorded at December 31, 2019.

For the year ended December 31, 2019, an increase to the after-tax discount rate used in the Company's impairment test of 2% or a US$2 decrease to the WTI price would not have resulted in an impairment charge.

At December 31, 2019 and December 31, 2018, the Company did not observe any indicators of impairment with respect to its Orion CGU.

In its December 31, 2018 independent reserve evaluator's report, the Company observed a decrease in the forecast construction and drilling and completion costs for the Taiga CGU. The revised cost estimates were based on the Company's costs incurred for the Orion Phase 2BC expansion and drilling of 18 wells pairs. The Company considered the significant decrease in future development costs as an indicator of impairment reversal for the Taiga CGU and performed an impairment test at December 31, 2018.

The Company estimated the recoverable amount of its Taiga CGU based on fair value less costs of disposal calculations. The fair value of the CGU was estimated based on the present value of after-tax cash flows resulting from production from proved and probable reserves from 2019 to 2063 using assumptions consistent with those used by the Company’s independent reserve evaluator, including capital and operating cost estimates, corporate tax rates, and a cost inflation factor of two percent, and using an after-tax discount rate of 12%.

The following forward prices and foreign exchange rates were used to estimate the recoverable amount as at December 31, 2018:

Year	Western Canadian Select (C$/bbl)	WTI at Cushing (US$/bbl)	Diluent (condensate) (C$/bbl)	AECO gas (C$/mmbtu)	Exchange rate (US$/C$)
2019	51.16	58.44	71.49	1.85	0.758
2020	59.13	63.75	79.33	2.28	0.776
2021	64.62	67.28	84.05	2.68	0.790
2022	67.57	70.50	87.17	2.99	0.790
2023	70.82	73.54	90.68	3.21	0.800
2024	72.54	75.27	92.70	3.37	0.805
2025	74.38	77.03	94.87	3.51	0.806
2026	76.36	78.90	97.22	3.59	0.806
2027	77.98	80.49	99.19	3.68	0.806
Remainder	+2.0% per year	+2.0% per year	+2.0% per year	+2.0% per year	0.806

Source: Average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule Associates and Deloitte Research Evaluation & Advisory price forecasts, effective January 1, 2019.

At December 31, 2018 the estimated recoverable value of the Taiga CGU exceeded the carrying value and the full impairment charge recorded in 2017 on the Taiga CGU of $135,525 was reversed.

The fair value measurements are categorized as level 3 with inputs that are not based on observable market data.

Exploration, evaluation ("E&E") and other other intangible assets

The Company's E&E assets are comprised of its Saleski Joint Venture, Saleski West, Sepiko Kesik, and Liege properties, located in the Saleski area and its Portage property located in the Athabasca area.

At December 31, 2019 and December 31, 2018, the Company did not observe any indicators of impairment or impairment reversal with respect to its E&E assets.

General and administrative ("G&A") expenses

For the years ended December 31,	2019	2018
Gross general and administrative costs	15,372	16,978
Capitalized salaries and benefits	(2,432)	(3,077)
Onerous lease settlements	—	(1,218)
Salaries and benefits related to pre-lease acquisition	—	(23)
Net general and administrative expenses	12,940	12,660

For the year ended December 31, 2019, gross G&A costs were $15,372 compared with $16,978 in the prior year. The 9% decrease mainly reflected lower operating costs and business taxes beginning in March 2019 following the renegotiation of the Company's head office lease, which included a 50% reduction in leased space. In addition, G&A in the prior year included head office rent which, upon the adoption of IFRS 16 on January 1, 2019, was recorded as principal and interest related to lease liabilities in 2019.

Capitalized G&A during the year ended December 31, 2019 of $2,432 decreased 21% from $3,077 in the prior year when significant internal resources were devoted to the Orion 2BC expansion project.

Share-based compensation expense

Total share-based compensation expense for the year ended December 31, 2019 was $10,963, an increase of $4,619 or 73% from $6,344 in the prior year. The increase was largely due to the impact of increases in the estimated fair value of the Company's share price from $3.10 at December 31, 2018 to $4.40 at December 31, 2019, along with an increase to the estimated performance share unit ("PSU") factor for PSUs vesting in March of 2020.

Net finance costs

For the years ended December 31,	2019	2018
Interest expense – long-term debt	27,850	20,804
Interest expense – deferred consideration	6,207	6,020
Amortization and derecognition of deferred transaction costs	3,523	1,955
Realized foreign exchange loss	535	141
Interest expense – lease liabilities	100	—
Interest income	(1,639)	(2,728)
Net finance costs	36,576	26,192

During the year ended December 31, 2019, the Company recorded net finance costs of $36,576, an increase of $10,385 from $26,192 in the prior year. The majority of the increase related to costs incurred or changes resulting from the amendment of the Company's senior secured first lien term loan effective June 30, 2019, which is discussed in detail in the "Statement of Financial Position Accounts" section below.

Interest expense on the Company's long-term debt increased due to a higher interest rate in the second half of 2019 on the portion of the loans that were extended and to a consent fee of $2,302 paid to lenders upon closing. Also, amortization and derecognition of deferred transaction costs increased in 2019 due to the derecognition of $2,130 of previously deferred transaction costs related to the extinguished loans.

Unrealized foreign exchange loss (gain) on long-term debt

The Company records an unrealized foreign exchange gain or loss upon translating the outstanding US$ principal balance on its senior secured term loans at each year end to C$ at the related foreign exchange rate.

During the year ended December 31, 2019, the Company recorded an unrealized foreign exchange gain of $12,427 compared with a loss of $21,595 in the prior year as the C$ strengthened during 2019, compared with weakening during 2018.

Accretion

For the year ended December 31, 2019, accretion expense related to decommissioning liabilities was $873, which was consistent with $887 in the prior year.

Deferred income tax recovery

During the year ended December 31, 2019, the company recorded a deferred tax recovery of $6,374, compared with a recovery of $22,452 in the prior year. The recovery was a result of higher 2P reserves, lower forecast capital and operating costs at Taiga and lower forecast natural gas pricing which led to the recognition of additional non-capital losses that were previously not recognized.

Statement of Financial Position Accounts

Adjusted working capital

The Company's adjusted working capital surplus increased by $26,162 to $82,133 at December 31, 2019 compared with a surplus of $55,971 at December 31, 2018. The changes during the year are summarized below:

Adjusted working capital	
Adjusted working capital surplus as at December 31, 2018	55,971
Netback	228,078
Interest income	1,639
Interest expense, principal payments and debt costs – term loans	(68,342)
Realized net loss on financial risk management contracts	(54,114)
Increase in current portion of long-term debt	(39,968)
Capital investment	(18,042)
Increase in current portion of share unit liabilities	(1,201)
General and administrative expenses and other	(14,083)
Settlements of share unit liabilities	(7,205)
Settlements of decommissioning liabilities	(600)
Adjusted working capital surplus as at December 31, 2019	82,133

At December 31, 2019, the Company’s adjusted working capital consisted of cash and cash equivalents of $125,576 (December 31, 2018 – $66,555) which included $11,098 (December 31, 2018 – $13,885) of restricted cash, accounts receivable of $26,063 (December 31, 2018 – $12,836) and prepaid expenses and other assets of $2,035 (December 31, 2018 – $1,856), less accounts payable, accrued liabilities and provisions of $22,925 (December 31, 2018 – $18,328), the current portion of long-term debt of $42,833 (December 31, 2018 – $2,865), the current portion of share unit liabilities of $5,284 (December 31, 2018 – $4,083) and the current portion of lease liabilities of $499 (December 31, 2018 – nil) .

Accounts receivable at December 31, 2019 were substantially related to petroleum sales, net of related diluent and product purchases, for the month of December 2019. Accounts payable and accrued liabilities at December 31, 2019 largely consisted of amounts incurred in the fourth quarter of 2019 in relation to operating costs and capital and administrative expenditures, along with transportation costs related to December 2019. The current portion of long-term debt at December 31, 2019 consisted of the cash sweep applicable to the fourth quarter of 2019 and to the portion of the term loans maturing on July 31, 2020.

Capital investment

For the year ended December 31, 2019	
Property, plant and equipment:	
Balance – beginning of year	679,972
Orion	15,701
Taiga	1,106
Corporate assets	186
Total cash investments	16,993
Capitalized share-based compensation	954
Right-of-use ("ROU") assets recorded upon adoption of IFRS 16	1,306
ROU asset additions	235
Changes to decommissioning liability	3,513
Total non-cash investments	6,008
Depletion & depreciation	(58,105)
Balance – end of year	**644,868**
Exploration and evaluation:	
Balance – beginning of year	27,077
Operated properties (SK, Saleski West, Liege and Portage)	745
Saleski joint venture	304
Total cash investments (net)	1,049
Changes to decommissioning liability	302
Capitalized depreciation	1,506
Total non-cash investments	1,808
Depreciation	(1,527)
Dispositions	(110)
Balance – end of year	**28,297**
Total cash capital investment (net)	18,042
Total non-cash capital investment	7,816
Total capital investment	**25,858**

For the year ended December 31, 2019, the Company invested a total of $25,858 in capital assets, of which $18,042 was funded by cash and $7,816 related to the non-cash impacts of capitalized share-based compensation, right-of-use asset additions and depreciation as well as changes in the Company’s provision for its decommissioning obligations.

Of the $25,858 of capital asset additions in the year ended December 31, 2019, $19,867 related to capital investment in Orion, $1,407 related to the Company's Taiga development at Cold Lake, $1,719 related to the Saleski JV and $1,138 related to exploration, evaluation, and development activities at SK, Saleski West, Liege and Portage. In addition, $1,541 was added through the recognition of ROU assets and $186 was spent on corporate assets. Included in the figures presented above, for the year ended December 31, 2019, are capitalized cash G&A and share-based employee-related costs of $3,386.

During the year ended December 31, 2019, the Company recorded $57,010 of depletion and $472 of depreciation related to its Orion project. There was no depletion charged against other oil sands projects as they were still in the development stage at December 31, 2019. During the year ended December 31, 2019, the Company charged $139 of depreciation against corporate assets, $21 of depreciation against other intangible assets and $484 of depreciation against ROU assets. During the year ended December 31, 2019, the Company capitalized $1,506 of Saleski joint venture pilot facility and infrastructure depreciation to its intangible E&E assets.

Long-term debt

Effective June 30, 2019, the Company's wholly-owned subsidiary, OPC, completed an amendment of its senior secured first lien term loan. As a result of the amendment:

- OPC made principal and amortization payments totaling US$10,525 at closing;
- US$172,120 of the term loan was extended by two years to July 31, 2022 (the "2022 Loans"); and
- US$17,905 of the term loan continued to have a maturity date of July 31, 2020 (the "2020 Loans").

The interest rate on the 2022 Loans varies between LIBOR plus 7.5% and 9.5% per annum depending on OPC's ratio of senior secured loans to earnings before interest, taxes and depreciation ("EBITDA"). The 2020 Loans continue to bear interest at LIBOR plus 5.5% per annum.

Depending on OPC's ratio of senior secured loans to EBITDA, 75% to 90% of OPC's cash flow in excess of deemed maintenance and sustaining capital spending is subject to a quarterly cash sweep that is applied against the principal balances of the loans.

In addition, on September 25, 2019, OPC completed an amendment to extend the maturity date of its US $15,000 senior secured first lien revolving loan by two years to April 30, 2022. The revolving loan remained undrawn at December 31, 2019 and 2018.

As at December 31, 2019, the balance of the term loans, net of unamortized debt issue costs, was $221,521 (December 31, 2018 – $270,917), which included $42,833 classified as current (December 31, 2018 – $2,865). The decrease in the C$ balance of the term loans from the prior year end mainly resulted from principal repayments of US$29,167 (2019 – C$38,552, 2018 – C$2,760) and translating the outstanding US$ principal into C$ at the December 31, 2019 exchange rate of US$1 = C$1.2990, compared with the December 31, 2018 rate of US$1 = C$1.3641.

The unamortized transaction costs associated with the 2020 Loans and 2022 Loans at December 31, 2019 of $1,787 (December 31, 2018 – $3,369) are being amortized over the lives of the related term loans utilizing the effective interest method. During the year ended December 31, 2019, $1,940 (2018 – $0) of debt issue costs were incurred, $2,130 (2018 – $0) of previously deferred debt issue costs related to the extinguished loans were derecognized and $1,392 (2018 – $1,955) of deferred debt issue costs were amortized against the loan balances.

Under the terms of the cash sweep, based on the results for the three months ended December 31, 2019, OPC is required to prepay US$18,753 of the principal balance of the term loans in the first quarter of 2020. This amount and the outstanding principal balance of the 2020 Loans due on July 31, 2020 are classified as a current liability at December 31, 2019.

Decommissioning liabilities

As at December 31, 2019 the Company estimated the net present value of its total future decommissioning liabilities to be $49,013 (December 31, 2018 – $44,925) of which $356 (December 31, 2018 – $793) was classified as current and recorded within accounts payable, accrued liabilities and provisions. The increase in the net present value was mainly due to lower discount rates at December 31, 2019, which ranged from 1.7% to 1.8%, compared with 1.9% to 2.2% at December 31, 2018. Discount rates are based on the Bank of Canada's risk-free bond rates. An inflation rate of 1.4% (December 31, 2018 – 1.4%) was used to calculate the future value of the decommissioning liabilities. At December 31, 2019, the Company estimated expenditures required to settle the liabilities will be made over the next 36 years with the majority of payments being made around 2045. During the year ended December 31, 2019, the Company incurred $600 of expenditures to settle decommissioning obligations (2018 – $929).

Share unit liabilities

As at December 31, 2019, the Company's share unit liabilities for those restricted share units ("RSUs") and PSUs expected to be settled in cash were $8,104 (December 31, 2018 – $6,503). The increase in the liability was primarily due to an increase in the share price to $4.40 at December 31, 2019 compared with $3.10 at December 31, 2018 and an increase in the estimated performance factor for PSUs vesting in March of 2020. As the Company's common shares do not trade in an active market, the fair values were estimated using an independent third party evaluation.

As at December 31, 2019, $5,284 (December 31, 2018 – $4,083) of the Company's share unit liabilities were classified as current, relating to those RSUs and PSUs scheduled to vest in the next 12 months. For share units that vest and are equity-settled, the Company estimated that it will pay an additional $4,430 in tax withholdings, of which $2,218 were expected to be incurred in the next 12 months. Such amounts are included in the Company's commitments in note 20.

Deferred consideration

In 2017, the Company recorded deferred consideration on the sale of a 4.0% GORR on its Orion property for cash proceeds. Deferred consideration is recognized in revenue based on the actual capital expenditures, operating expenses, abandonment costs and crown royalties incurred in the period related to the royalty owner's share of production relative to the total of those forecast costs for the royalty owner's share of proved plus probable reserves.

A reconciliation of deferred consideration for the year ended December 31, 2019 and 2018 is shown below:

For the years ended December 31,	2019	2018
Balance – beginning of year	64,048	64,047
Implied interest benefit	6,207	6,020
Revenue – deferred consideration	(2,787)	(5,991)
Transaction costs	—	(28)
Balance – end of year	67,468	64,048
Less: current portion of deferred consideration	(1,420)	(1,156)
Deferred consideration	66,048	62,892

Deferred tax asset

The Company recognized a deferred tax asset as at December 31, 2019 of $63,280 (December 31, 2018 – $56,906). The deferred tax asset resides entirely in OPC and the increase was the result of higher 2P reserves, lower forecast capital and operating costs at Taiga and lower forecast natural gas pricing which led to the recognition of additional non-capital losses that were previously not recognized.

As at December 31, 2019 the Company had approximately $1,068,726 in available tax pools, including operating loss carry forwards of $535,910 which are available to offset future taxable income. These operating losses start to expire in 2031.

Management's forecasts indicate that it is likely that future taxable profits will be sufficient to utilize the losses prior to expiry.

Shareholders' equity

	December 31, 2019	December 31, 2018
Common shares	1,035,592	1,032,554
Contributed surplus	67,484	67,410
Cumulative deficit	(598,267)	(631,862)
Total shareholders' equity	504,809	468,102

The balance in common shares increased to $1,035,592 at December 31, 2019 from $1,032,554 at December 31, 2018 due to shares issued upon the vesting and settlement of RSUs and PSUs.

During the year ended December 31, 2019, contributed surplus increased to $67,484 from $67,410. The increase was mainly the result of regular vesting of stock options and share units expected to be settled in shares, mostly offset by the settlement of share units in the year.

The decrease in the cumulative deficit from $631,862 at December 31, 2018 to $598,267 at December 31, 2019 was due to net income in 2019.

Equity Securities

During the year ended December 31, 2019, there were: 462,900 stock options granted; 180,850 stock options forfeited or expired; 559,700 RSUs and 897,400 PSUs granted; 939,735 RSUs and 1,760,820 PSUs vested; and 138,400 RSUs and 78,700 PSUs forfeited.

As at December 31, 2019 and December 31, 2018, the following common shares and stock options were issued and outstanding. In addition, as at December 31, 2019 and December 31, 2018, the following number of issued and outstanding RSUs and PSUs were expected to be settled in exchange for common shares of the Company:

(thousands)	December 31, 2019	December 31, 2018
Common shares outstanding	131,917	131,036
Stock options	6,085	5,803
Restricted share units	510	723
Performance share units	838	1,217
Total including dilutive securities	139,350	138,779

Long-term incentives plans

To ensure the Company's long-term incentives plans remain competitive in the marketplace, the Company's Board of Directors periodically reviews the plans' effectiveness as part of the Company's total compensation program to attract, retain and motivate key personnel, encourage commitment to the Company and its goals, align staff interests with the interests of shareholders and reward staff for performance. In doing this review during 2019, the Board of Directors considered publicly available data and information from external sources. On March 26, 2020, the Company's Board of Directors approved for issuance grants of up to 371,600 RSUs and 1,050,000 PSUs to employees, directors and contractors.

Liquidity, Financial Resources and Outlook

The Company's capital includes its working capital, senior secured credit facilities and share capital. At December 31, 2019, the Company had $82.1 million of working capital, before the current portions of net unrealized hedging liabilities and deferred consideration.

During the year ended December 31, 2019, the Company completed an amendment of its senior secured first lien term loan which resulted in over 90% of the outstanding balance being extended by two years to July 31, 2022, and made principal repayments totaling US$29,167 or C$38,552, resulting in an outstanding balance of US$171,908 or C$223,308 at year-end.

At December 31, 2019, OPC was in full compliance with its asset-based financial covenants. Further, OPC has access to an undrawn US$15,000 revolving line of credit, which was also extended during 2019 and matures on April 30, 2022.

Included in working capital at December 31, 2019 was US$32,974 or C$42,833 of principal to be repaid by July 31, 2020 related to the cash sweep for the fourth quarter of 2019 and the maturity of the non-extended portion of the term loan. Quarterly cash sweeps during 2020 may lead to further debt reduction.

Following the completion of Orion Phase 2BC in 2019, capital requirements for the expanded central processing facility were reduced. Capital expenditures in 2020 are expected largely to be limited to maintenance projects.

As a means to manage its capital exposure, the Company has an active commodity hedging program that is executed over time on a rolling basis targeting 50% of forecast bitumen production, net of maximum royalties.

Contractual Obligations and Commitments

The information presented in the table below reflected management's estimate of the contractual maturities of the Company's obligations for its oil sands properties and its general corporate activities as at December 31, 2019.

	Total	2020	2021	2022	2023+
Contracts and purchase orders (1)	3,218	3,030	155	33	—
Transportation agreements (2)	70,310	16,576	13,076	10,621	30,037
Outstanding share units (3)	8,526	2,560	3,103	2,863	—
Interest and fees on term loan (4)	45,363	18,335	17,191	9,837	—
Repayment of term loan (4)	223,308	42,833	—	180,475	—
Total	350,725	83,334	33,525	203,829	30,037

(1) Minimum commitments or buyouts relating to contracts and purchase orders, including those related to the Orion expansion projects, costs for the storage of the evaporators procured for use at Taiga, future operating costs for the head office lease and information technology contracts.
(2) Firm service gas and bitumen blend transportation commitments.
(3) Cash taxes related to share units expected to be settled in shares and unaccrued fair value of outstanding share units expected to be settled in cash.
(4) Minimum obligations under the term loans using the foreign exchange and interest rates in effect at December 31, 2019.

Risk Factors

The Company is exposed to a number of business risks, some of which are common to all businesses, while others are specific to the sector in which the Company operates. The following discussion reviews these general and specific risks and includes the Company's approach to managing these risks. These risks can be categorized as operational, financial, regulatory and cyber security.

Operational risks

Operational risks include risks associated with health and safety, resource exploration and development, project construction, commercial production and the Company's ability to retain and attract key personnel.

The development and operation of the Company's properties are subject to hazards of finding, recovering, transporting and processing hydrocarbons including, but not limited to: blowouts; fires; explosions; gaseous leaks; migration of harmful substances; oil spills; corrosion; acts of vandalism and terrorism; and other accidents or hazards that may occur at or during transport to or from commercial or industrial sites. Any of these hazards can interrupt development, including facility construction, and operations, impact the Company's reputation, cause loss of life or personal injury, result in loss of or damage to equipment, property, information technology systems, related data and control systems, cause environmental damage that may include polluting water, land or air, and may result in fines, civil suits, or criminal charges against the Company.

A significant source of risk with regard to resource development is accurately estimating the quantities of reserves and resource given the level of uncertainty inherent in such estimates. As such, no assurance can be given that the indicated level of reserves or resource or recoverable bitumen will be realized. In general, estimates of resource and of economically recoverable bitumen reserves are based upon a number of factors, such as geological and engineering estimates, the assumed effects of regulation by governmental agencies, royalties and estimates of future commodity prices, operating costs and capital costs, all of which may vary considerably from actual results. Estimates based solely on these methods are generally less certain than those based on production history. Reserves and resource estimates may require revision based on actual production experience and data as they become available in future periods. Potential changes in reserves and resource estimates in future periods could have a material impact on the net asset value of the Company, its operations, and its ability to obtain financing.

Project construction requires specialized labour, equipment, engineering expertise and construction management. There can be no assurance that all of the specialized labour and equipment will be available at the times or costs projected in the Company's current plans. The Company may experience shortages of specialized labour and equipment, labour disruptions and increases in compensation and equipment costs. Productivity of construction personnel is an important factor in developing its planned projects. Should low productivity occur, it may result in project completion delays and an increase in project costs. The Company currently does not have regulatory approvals for the development of all phases of its projects. These regulatory approvals may delay or restrict the development of the projects.

The success of current and future commercial production is dependent on effective extraction of identified reserves and resources. The actual performance of Steam Assisted Gravity Drainage ("SAGD"), Cyclic Steam Stimulation ("CSS") and other potential recovery techniques may differ from expectations and to date those techniques have not been applied on a commercial scale to carbonate reservoirs. There are many factors related to the characteristics of the reservoir and SAGD/CSS operating facilities that could cause bitumen production to be lower than anticipated. In addition, the Company may develop and implement alternative extraction processes that have not been widely used in the industry and whose results could differ from expectations.

The Company’s overall success also depends on its management team and key technical and other personnel to run the business and execute on its project development plans. The loss of any of these key individuals could have a material adverse effect on the Company and the development of its assets. Due to the specialized nature of the Company’s business, the Company believes that its future success will also depend upon its continued ability to attract, retain and motivate skilled and experienced management, technical, operations and marketing personnel.

The Company manages these operational risks and hazards by maintaining a diversified portfolio of assets, as well as by assembling and retaining an experienced management and technical team with the requisite skills to plan and either execute, or outsource to experienced third-party professionals, all aspects of the development, construction, and production stages of the projects. In addition, the Company maintains certain insurance policies to mitigate the risks associated with potential operational hazards. While there can be no certainty that the insurance policies will be sufficient to cover all potential hazards, they are considered appropriate given the nature of the Company’s business and the current stage of development of its projects.

Financial and market risks

The development of oil sands projects requires a significant amount of capital investment that occurs over a number of years and prior to the commencement of commercial operation of the Company’s projects. As a result, the Company’s projected capital expenditures required to develop future commercial operations beyond the Orion project are expected to be greater than working capital currently available. While the Company is in a strong financial position, it will be necessary to build working capital in future periods through cash flow from Orion operations, or to complete additional equity, debt, or other financings in future periods in order to advance future projects. The inability of the Company to generate or access sufficient capital for those activities could have a material adverse effect on the timing of project development and its financial condition, results of operations, or prospects.

The Company has existing debt and may take on additional debt in the future to finance any portion of its planned development activity. There can be no guarantee that it will have sufficient funds from available equity or cash flow from operations to make payments with respect to its indebtedness or to fund its other liquidity needs. In these circumstances, the Company may need to refinance all or a portion of its debt on or before maturity. The Company's ability to refinance its indebtedness will depend upon, among other things, future financial and operating performance and prevailing economic, business, regulatory, market and other conditions, some of which are beyond the Company's control. There can be no guarantee that the Company will be able to refinance any of its indebtedness on commercially reasonable terms, or at all.

In addition, as the Company reports its operating results in C$, fluctuations in product pricing and in the rate of exchange between the US$ and C$ affect the Company’s reported results. Further, all of the Company's long-term debt is denominated in US$ and is at a variable interest rate. Fluctuations in exchange rates and interest rates may significantly increase or decrease the amount of debt and interest expense recorded in the Company's financial statements, which could have a significant effect on the Company's results of operations, financial condition and prospects.

With the recent and projected growth in production from unconventional sources in North America, additional infrastructure (e.g., pipeline and rail capacity) is required to transport all the current and potential production to the desired markets. These projects have generally been identified. There is considerable risk that any one or more of the projects may not proceed in line with current timing estimates, or at all. Insufficient transportation capacity for the Company's production will impact its ability to efficiently access end markets. This may negatively impact the Company's financial performance by way of higher transportation costs, wider price differentials, lower sales prices at specific locations and voluntary or mandated production curtailment.

Markets for blended bitumen produced by the Company exist within North America; however, crude oil demand and price as well as market differentials for bitumen blend are affected by North American and, in the case of crude oil, worldwide supply and demand fundamentals that are beyond the control of the Company. World oil prices and blended bitumen differentials have fluctuated widely in recent years. Material declines in oil prices or widening of blended bitumen differentials could reduce future net production revenue. Certain wells or other projects may become uneconomic, leading to a reduction in the volume of the Company's bitumen resources and reserves. The Company also might elect not to produce from certain wells at lower prices.

The Company's revenues are based on the US$, since revenue received from the sale of bitumen and bitumen blends is generally referenced to a price denominated in US$. The Company incurs most of its operating and other costs in C$. As a result, the Company is impacted by exchange rate fluctuations between the US$ and the C$, and any strengthening of the C$ relative to the US$ could negatively impact the Company's operating margins and cash flows.

The Company also has significant exposure to electricity costs and natural gas prices during the project life as the majority of the energy required to generate steam for SAGD and CSS operations is from natural gas. High electricity costs and/or natural gas prices could result in a material increase in operating costs. In addition, the Company is exposed to condensate costs given that wellhead bitumen is blended with condensate to deliver production to market. Should condensate costs increase disproportionately more than the price the Company is able to obtain for blended bitumen sales, the Company's overall profitability could be affected.

The Company may utilize financial instruments to manage the exposure to market risks relating to foreign exchange rates, commodity and electricity prices and product price differentials which, alone or together, may have an adverse effect on its financial results, condition and prospects. All of these factors could result in a material decrease in the Company's future net production revenue, negatively impacting its oil sands exploration and development activities.

During the year ended December 31, 2019, the Company continued to execute its commodity hedging program. The Company's hedging objective is to increase the certainty of C$ operating cash flows as a source of funding by reducing commodity price and related foreign exchange volatility. The Company mitigates market risks by using financially-settled derivatives to hedge over time and on a rolling basis a set percentage of its forecast bitumen production, net of maximum royalties. For the first half of 2019, due to excessive market volatility, the target was 70%. In the second half it was 60% and for later periods it is 50%. The program includes the hedging of natural gas and condensate purchases.

Management monitors credit and counterparty concentration risks related to the risk management contracts but considers them acceptable due to the size and financial strength of the counterparties.

For the year ended December 31, 2019, realized net gains (losses) on financial risk management contracts were:

Swaps – WTI	(7,605)
Swaps – WTI/WCS differential	(49,837)
Swaps – Condensate differential	2,589
AECO Gas	739
Net realized loss on financial risk management contracts	(54,114)

As at December 31, 2019, the following financial risk management contracts were in place:

	2020				
WTI	Q1	Q2	Q3	Q4	Total
bbl/d	8,840	7,750	8,850	8,850	
Avg. price ($/bbl)	76.96	74.32	73.62	73.47	
Fair value	(1,432)	(1,860)	(1,001)	264	(4,029)
WTI-WCS differential					
bbl/d	11,920	10,450	12,000	12,000	
Avg. price ($/bbl)	(28.72)	(28.08)	(26.97)	(27.23)	
Fair value	(867)	(4,783)	(5,193)	(4,469)	(15,312)
WTI-Condensate differential					
bbl/d	3,100	2,700	3,100	3,100	
Avg. price ($/bbl)	(5.90)	(5.97)	(5.93)	(5.94)	
Fair value	2,213	621	(309)	(9)	2,516
AECO gas					
GJ/d	11,150	9,500	11,150	11,150	
Avg. price ($/GJ)	1.67	1.58	1.57	1.62	
Fair value	372	11	109	321	813
Total fair value	286	(6,011)	(6,394)	(3,893)	(16,012)

To the extent that the Company is not the operator of its properties, such as the Saleski joint venture, the Company is dependent upon third parties for the timing and scope of activities. In addition, there is no certainty that third-party operators will be able to meet financial commitments to a particular project which could have a material adverse effect on the viability of these projects and the business and operations of the Company.

Inflation risks subject the Company to potential erosion of product netbacks and overall profitability. For example, domestic prices for construction equipment and services and oil production equipment and services can inflate the costs of project development and increase future operating costs.

The Company manages these risks through effective capital budgeting, financial and market forecasting and planning, expenditure and commitment monitoring and long-term corporate planning. The Company assesses projects on stringent investment criteria. In addition, the Board of Directors reviews and approves the annual operating and capital budgets and any material changes in the amount or scope to the budgets.

Regulatory risks

The Company's business is subject to substantial regulation under provincial and federal laws relating to the exploration for, and the development, processing, production, marketing, pricing, taxation, and transportation of oil sands bitumen and related products and other matters. Amendments to current laws and regulations governing operations and activities of oil sands operations could have a material adverse impact on the Company's business. In addition, there can be no assurance that laws, regulations and government programs related to the Company's projects and the oil sands industry will not be changed in a manner which may adversely affect the projects and cause delays or inability to complete the projects. Permits, leases, licences, and approvals are required from a variety of regulatory authorities at various stages of the Company's projects. There can be no assurance that the various government permits, leases, licenses and approvals sought will be granted in respect of the projects or, if granted, will not be cancelled or will be renewed upon expiry. There is no assurance that such permits, leases, licences, and approvals will not contain terms and provisions which may adversely affect the final design and/or economics of the Company's projects. The Company currently does not have regulatory approvals for the development of all phases of its projects. These regulatory approvals may delay or restrict the development of the projects.

In an effort to address the historically wide Canadian oil price differentials experienced in late 2018, on December 2, 2018 and effective January 2019, the Government of Alberta announced a curtailment of oil production in the Province for up to 12 months, which was extended in August 2019 to up to 24 months. The Company is among the operators affected by the curtailment rules and at times has been forced to reduce production to levels below its operating capability. The level of curtailment, if any, is determined on a month-to-month basis. To the extent this provincial curtailment or other future curtailments are in place and depending on the production ceiling allocated, the Company's operating efficiency and cash flows may be negatively impacted. In addition, depending on the level and duration of curtailment, there could be adverse impacts on the Company's ability to recover bitumen reserves and resource.

Future development of the Company's projects is dependent on maintaining its current oil sands leases and licences and receiving required regulatory approvals and permits on a timely basis. Maintenance of the Company's undeveloped oil sands leases and licenses requires a Minimum Level of Evaluation in the form of drilling, seismic and/or other delineation activity. There can be no guarantee that the Company will have sufficient capital, human or other resources to satisfy all its current requirements, or that the requirements will not be modified.

The Government of Alberta has initiated a process to control cumulative environmental effects of industrial development through the Lower Athabasca Regional Plan ("LARP"). While the LARP has not had a significant effect on the Company, there can be no assurance that changes to the LARP or future laws or regulations will not adversely impact the Company's ability to develop or operate its projects. All phases of the oil and natural gas business present environmental risks that are subject to environmental regulation pursuant to a variety of national and international conventions, as well as municipal and provincial laws and regulations. These laws and regulations require that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities.

Production and future development of the Company's resources will result in the emission of greenhouse gases ("GHGs") and other industrial air pollutants, which the federal and provincial governments have announced intentions to regulate. In October 2016, the Government of Canada announced a pan-Canadian approach to the pricing of carbon emissions. In 2018, the federal government finalized the Greenhouse Gas Pollution Pricing Act under its Carbon Strategy, which specifies (i) a carbon price on fossil fuels of $20 per tonne of carbon dioxide equivalent ("CO2e") in 2019, rising by $10 per year to $50 per tonne CO2e in 2022 and (ii) an Output-Based Pricing System ("OBPS") for industrial facilities with annual emissions of 50 kilotonnes of GHG per year or more. OBPS facilities will be subject to the carbon price on the portion of emissions that exceed an annual output-based emissions limit, which can be satisfied by paying a charge, applying federally issued surplus credits or eligible offset credits. The federal carbon pricing system will apply only in jurisdictions that do not have equivalent measures in place.

Effective January 1, 2020, the Province of Alberta's Technology Innovation and Emissions Reduction ("TIER") system replaces the Carbon Competitiveness Incentive Regulation ("CCIR"). The TIER system has been deemed equivalent to the federal output-based pricing system for 2020. The TIER system automatically applies to industrial sources that emit greater than 100,000 tonnes of GHG emissions per year, including the Company's Orion project. Facilities subject to TIER are required to meet an emissions intensity benchmark which is set based on industry or facility performance. Where emissions exceed the benchmark, the facility must reduce its net emissions by applying emissions offsets, emissions performance credits or fund credits against its actual emissions level. There can be no assurance as to the Company's expected emissions performance, the industry's emissions performance or the resultant compliance costs to the Company. Material compliance costs could materially impact the economics of the Company's operations and development projects.

As a specialized agency of the United Nations and the main regulatory body for the shipping industry, the International Maritime Organization (“IMO”) is the global standard-setting authority for the safety, security and environmental performance of international shipping. IMO has set a global limit for sulphur in fuel oil used on board ships of 0.5 weight percent from January 1, 2020, substantially below the current upper limit of 3.5 weight percent. The IMO’s goal is to significantly reduce the amount of sulphur oxide emanating from ships and it expects major health and environmental benefits for the world, particularly for populations living close to ports and coasts. In the few months since its introduction, the IMO sulphur regulation has led to a widening of the light to heavy crude oil differential, negatively impacting pricing for heavier crude oils including bitumen and increased price volatility. Longer term, the impact will depend on the degree of enforcement of the regulation, the willingness of shipowners to install scrubbers, worldwide heavy sour crude production and additional heavy processing availability.

The federal *Species at Risk Act* and provincial *Wildlife Act* regulate threatened and endangered species and may limit the pace and amount of development in areas identified as critical habitat for species of concern such as Woodland Caribou. The federal and/or provincial implementation of measures to protect species at risk such as Woodland Caribou and their critical habitat in areas of the Company’s current or future operations may modify the Company’s pace and amount of development in affected areas.

Compliance with such legislation and the laws and regulations discussed above can require significant expenditures, and a breach may result in the imposition of fines and penalties, some of which may be material. To manage these risks, the Company has both in-house expertise and also hires third-party consultants to advise on environmental and safety compliance matters. The Company makes environmental stewardship and safety the highest priorities in its project planning, budgeting, execution and operation.

The development of the Company’s projects relies on securing licences for non-potable groundwater withdrawal, and there can be no assurance that these licences will be granted on terms favourable to the Company or at all, or that such water will in fact be available to divert under such licences. In addition, there can be no assurance that the licences to withdraw groundwater, when granted, will not be rescinded or that additional conditions will not be added to these licences. There can be no assurance that the Company will not have to pay a fee for the use of water in the future or that any such fees will be reasonable.

The Company is also subject to risk in relation to potential stakeholder objections, including those originating from Indigenous peoples who have claimed title and/or have certain treaty or traditional rights in relation to large areas of land in the province of Alberta, including to the entirety or specific portions of current and future commercial regulatory applications associated with its oil sands projects. Such objections can result in having to participate in a regulatory hearing to reach a resolution, which may have an impact on the timing of project execution and have an adverse effect on the Company’s future financial condition or ability to proceed.

The Company manages these risks by employing and contracting stakeholder, environmental and regulatory experts to ensure that: it prepares and submits high quality regulatory project applications; initiates and maintains positive relationships with all stakeholders; and conducts all operations in an environmentally responsible manner.

Reputation risk

The Company relies on its own and the industry's reputations to build and maintain positive relationships with investors and stakeholders, to recruit and retain staff, and to be a trustworthy partner in the community. Public perception of Alberta's oil sands has the potential to impact the Company's reputation, which may adversely affect its value, development plans and ability to continue operations.

Development of the Alberta oil sands has received considerable attention on the subjects of environmental impact, climate change, GHG emissions and Indigenous engagement. The influence of anti-fossil fuels and, more specifically, anti-oil sands activists targeting equity and debt investors, lenders and insurers may result in policies which reduce support for or investment in the Alberta oil sands sector. Concerns about oil sands may, directly or indirectly, impair the profitability of the Company's current oil sands operations and the viability of future oil sands projects by creating significant regulatory and economic uncertainty, leading to delays relating to the sanctioning of future projects. In addition, evolving decarbonization policies of institutional investors, lenders and insurers could affect the Company's ability to access capital pools. Certain insurance companies have taken actions or announced policies to limit available coverage for companies which derive some or all of their revenue from the oil sands sector. As a result of these policies, premiums and deductibles for some or all of the Company's insurance policies could increase substantially. In some instances, coverage may become unavailable or available only for reduced amounts of coverage. As a result, the Company may not be able to extend or renew existing policies, or procure other desirable insurance coverage, either on commercially reasonable terms, or at all.

In addition, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil, reduce its price and may result in stranded assets or an inability to further develop oil resources.

Disease outbreaks

A local, regional, national or international outbreak of a contagious disease, including COVID-19, Severe Acute Respiratory Syndrome, H1N1 influenza virus, avian flu, or any other similar illness could result in outcomes that have a material adverse effect on the business, financial condition and results of operations of the Company.

The outbreak of COVID-19 has resulted in governments worldwide enacting emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and social distancing, have caused material disruption to businesses globally resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions. The duration and impact of the COVID-19 outbreak is unknown at this time, as is the efficacy of the government and central bank interventions. It is not possible to reliably estimate the length and severity of these developments and the impact on the financial results and condition of the Company in future periods.

Cyber security risk

The Company utilizes a number of information technology systems for the administration and management of its business, including the safe operation of its Orion facility. If the Company's ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on the Company and its operations. Further, although the Company's information technology systems are considered to be secure, if an unauthorized third party is able to access the systems then such unauthorized access may compromise the Company's business in a materially adverse manner.

The Company manages these risks by: employing technical countermeasures such as anti-virus software and network firewalls; providing ongoing training and education of staff through initiatives such as simulated phishing emails; requiring all changes to security and access to be logged and audited in a tracking system; and through design decisions by isolating and fortifying critical parts of the Company's information infrastructure.

Critical Accounting Estimates and Judgments

The timely preparation of financial statements in accordance with IFRS requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and disclosure of contingencies at the dates of the annual consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. The estimated fair value of assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur. Significant judgments, estimates and assumptions made by management in the preparation of these consolidated financial statements are outlined below.

Sale of a royalty interest

When the Company sells a royalty interest linked to production at a specific property, judgment is required in assessing the appropriate accounting treatment of the transaction on the closing date and in future periods. The Company considers the specific terms of the arrangement to determine whether it has entered into a financing arrangement, disposed of an interest in the reserves of a property, and/or received an upfront payment for future services. This assessment considers the economic substance of the arrangement including the Company's method of settlement, the risks assumed by the royalty owner, the duration of the arrangement, the property or properties to which the royalty applies, the timing of the royalty owner's investment including any potential future payments, any penalties for the Company failing to deliver the royalty, the royalty owner's involvement in the Company's ongoing decision-making, and any commitments made by the Company to develop future expansions or projects at the property. To the extent it is determined that there is an upfront payment for future services, judgment is required to estimate the value of such services.

Bitumen reserves and resource

The estimation of reserves and resource involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital and operating expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves and resource estimates can have a significant impact on net income (loss), as they are key components in the calculations of depletion and deferred consideration and for determining potential asset impairment or reversals thereof. Reserves and resource estimates for properties in PP&E are prepared by independent reserve engineers at least annually. Independently prepared resource estimates for E&E properties may be prepared less frequently but at minimum are reviewed and, if necessary, updated by management annually.

Financial risk management contracts

The fair value of financial risk management contracts is dependent on estimates of forward commodity prices, differentials and foreign exchange rates. While forward prices and rates at the balance sheet date were determined based on observable market data, they will likely differ from future prices and rates and significantly impact the fair value of financial risk management contracts.

Carrying value of exploration and evaluation assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

Identification of cash generating units

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures, and the way in which management monitors the Company's operations.

Leases

The Company uses judgment when assessing all contracts to determine if the contract contains a lease. Contracts identified as containing a lease are subject to further judgment and estimation to determine the lease term and discount rate. The Company considers relevant economic and operational factors when deciding to include extension options in the lease term. When the implicit discount rate of a lease is not available, lease liabilities are estimated using a discount rate similar to the Company's incremental borrowing rate.

Provisions

Provisions are recognized for the future decommissioning and restoration of the Company's oil and gas assets to be incurred at the end of their economic life. The reported amount of the obligation is based on estimated future costs for the abandonment of the assets and reclamation of the site to its original state discounted at a risk-free rate and must be reevaluated each reporting period. Estimating the timing, amount and present value of these retirement costs requires significant judgment. By their nature, these estimates, as they become available, are subject to measurement uncertainty, and the impact on the consolidated financial statements could be material.

The Company recognizes a provision relating to its head office lease equal to the present value of the difference between the minimum future lease payments that the Company is obligated to make under the lease until its expiry, including estimated future operating costs, less estimated sublease recoveries. Actual recoveries and operating costs may differ significantly from these estimates.

In addition, the Company makes estimates of potential provisions owing within accounts payable, accrued liabilities and provisions which may include amounts disputed in the normal course of business. Amounts ultimately paid may differ significantly from these estimates.

Share-based compensation

The Company uses a fair value-based method of accounting for share-based compensation for all awards of shares, performance warrants, stock options, RSUs and PSUs. The Black-Scholes pricing model is used to estimate the fair value of stock options and performance warrants on the date of grant. The Black-Scholes pricing model includes inputs such as discount rates, expected exercise dates, and expected volatility, which are subject to judgment and may not be indicative of future experience. Into its vesting models, management has incorporated an estimated forfeiture rate, which is also subject to judgment. The liability for the portion of share unit awards that is expected to be settled in cash is based on an estimate of the Company's share price at the reporting date established by the Company's board of directors after considering a third-party estimate of fair value and an assumption that staff will elect to receive the maximum cash award. As the Company is a private entity, its estimated share price is subject to significant judgment.

Deferred income taxes

The determination of deferred income tax assets and liabilities requires interpretation of complex laws and regulations, and they are recognized at tax rates expected to be in effect at the estimated timing of reversal of temporary differences between the accounting and tax treatment of certain assets and liabilities. To the extent these judgments change, there may be a significant impact on the consolidated financial statements of future periods.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an estimation of the amount of future taxable earnings, the availability of taxable income to offset the tax assets when the reversal occurs and the application of tax laws. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the consolidated financial statements of future periods.

Quarterly Results

Although the Company's netback of $51,108 for the three months ended December 31, 2019 was lower than the previous two quarters, Osum achieved record high average production of 20,539 bbl/d in the fourth quarter. A wider WTI-WCS differential in the period contributed to an average realized bitumen price of $41.12/bbl, the lowest of any quarter during 2019.

Royalties were $2.94/bbl and total unit operating costs were $11.13/bbl for the three months ended December 31, 2019. Lower royalties per barrel compared with the first three quarters of 2019 was consistent with the lower realized bitumen price. The unit operating costs were lower than the first half of 2019 mainly due to higher production. The Company was not subject to Provincial curtailment during the three months ended December 31, 2019, so there were no curtailment allotment purchases in the period.

The strong fourth quarter netback was slightly offset by a net realized loss on risk management contracts of $5,457 or $2.89/bbl, leading to a netback after hedging of $45,651 or $24.16/bbl.

Net income for the three months ended December 31, 2019 was $28,473. Quarterly net income varied widely between quarters in 2019 mainly due to the impacts of volatile forecast commodity prices on unrealized gains and losses on risk management contracts and of changes in the C$/US$ foreign exchange rate on unrealized gains and losses on long-term debt.

Other than funds flow, netback, adjusted netback and adjusted working capital, all non-IFRS measures, the figures as reported in the following table for the eight most recent quarters are presented in accordance with IFRS.

	2019				2018			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Business Environment (1)								
West Texas Intermediate (WTI) – US$/bbl	56.98	56.45	59.83	54.90	58.83	69.50	67.90	62.89
Cold Lake Blend (CLB) – US$/bbl	40.70	44.72	49.17	41.88	19.44	45.92	47.49	37.53
Differential – WTI less CLB – US$/bbl	16.28	11.73	10.66	13.02	39.39	23.58	20.41	25.36
Differential – CLB % of WTI	28.6%	20.8%	17.8%	23.7%	67.0%	33.9%	30.1%	40.3%
Foreign exchange rate – C$/US$	1.3200	1.3208	1.3375	1.3296	1.3215	1.3071	1.2911	1.2653
CLB – $/bbl	53.72	59.07	65.76	55.68	25.69	60.02	61.31	47.49
AECO – $/mcf	1.32	0.86	0.96	2.48	1.48	1.12	1.18	2.07
Operational (1) (2)								
Bitumen production – bbl/d	20,539	19,306	19,587	15,505	15,424	11,398	8,549	8,880
Blended bitumen sales – bbl/d	28,117	25,867	26,330	21,786	21,307	15,479	12,045	12,509
Petroleum sales less product purchases and diluent and transportation costs – $/bbl	41.12	51.10	54.34	49.37	1.14	44.15	43.91	27.92
Royalties – $/bbl	(2.94)	(3.69)	(4.58)	(3.25)	(1.12)	(3.99)	(4.22)	(2.17)
Non-fuel operating costs – $/bbl	(8.05)	(8.52)	(8.47)	(10.62)	(8.19)	(10.07)	(14.23)	(12.63)
Fuel costs – $/bbl	(3.08)	(1.50)	(1.56)	(3.84)	(2.35)	(1.55)	(2.12)	(3.69)
Curtailment allotment purchases – $/bbl	—	(1.33)	(1.15)	(0.05)	—	—	—	—
Netback (3) – $/bbl	27.05	36.06	38.58	31.61	(10.52)	28.54	23.34	9.43
Realized gain (loss) on financial risk management contracts – $/bbl	(2.89)	(7.85)	(12.30)	(9.16)	13.21	(5.48)	(9.07)	2.53
Adjusted netback (3) – $/bbl	24.16	28.21	26.28	22.45	2.69	23.06	14.27	11.96
Financial								
Netback (3)	51,108	64,070	68,786	44,114	(14,922)	29,922	18,158	7,538
Realized risk management contracts	(5,457)	(13,941)	(21,929)	(12,787)	18,752	(5,748)	(7,054)	2,019
Adjusted netback (3) – $/bbl	45,651	50,129	46,857	31,327	3,830	24,174	11,104	9,557
Funds flow (4)	34,877	39,734	29,051	22,593	(4,998)	16,057	3,198	962
Cash flows from operating activities	37,875	35,622	35,824	7,643	1,412	11,760	5,974	587
Net and comprehensive income (loss)	28,473	14,398	31,386	(40,663)	158,970	19,628	(22,148)	(20,897)
Net income (loss) per share (basic) – $ (5)	0.22	0.11	0.24	(0.31)	1.21	0.15	(0.17)	(0.30)
Capital investment (6)	4,921	2,948	5,919	4,254	6,839	37,397	62,760	58,760
General and administrative expenses (net) (7)	3,737	3,205	2,643	3,355	3,501	3,054	2,822	3,454
Cash and cash equivalents (8)	125,576	114,803	83,587	68,805	66,555	89,337	125,206	181,828
Adjusted working capital (9)	82,133	77,841	82,585	70,680	55,971	70,313	91,297	151,699
Outstanding principal – long-term debt (10)	180,475	207,220	246,050	264,930	271,421	257,575	262,773	258,669
Shareholders' equity	504,809	475,763	460,777	428,796	468,102	308,428	286,863	308,432
Weighted average common shares outstanding	131,917	132,498	131,630	131,036	131,036	131,020	130,994	130,981

(1) Business environment and operational metrics are averages for the period.
(2) Dollar per barrel metrics are calculated based on bitumen production volumes. Quarter-over-quarter per barrel metrics may be affected by differences between the timing of bitumen production and blended bitumen sales.
(3) Netback is calculated by deducting the related diluent, transportation, product and curtailment allotment purchases, royalties and field operating costs from petroleum sales. Adjusted netback is calculated by adjusting the netback to include realized gains and losses on financial risk management contracts.
(4) Funds flow is calculated as cash flows from operating activities before changes in non-cash operating working capital, which is presented on the consolidated statement of cash flows.
(5) For the three months ended December 31, 2018, diluted net income per share was $1.18. For all other periods, diluted net income (loss) per share was the same as net income (loss) per share.
(6) Capital investment includes capitalized general and administrative expenses but excludes capitalized stock-based compensation expense.
(7) General and administrative expenses (net) is calculated after reductions for capitalized salaries and benefits, onerous lease payments and exploration costs.
(8) Cash and cash equivalents include restricted cash.
(9) Adjusted working capital is calculated as working capital adjusted to exclude the current portions of risk management contracts, which are fair value estimates of unrealized gains and losses and are subject to a high degree of volatility prior to ultimate settlement, and deferred consideration, which does not impact cash.
(10) Outstanding principal of long-term debt consists of the non-current portions of the outstanding principal balances of the term loans and any amounts outstanding under the revolving loan, translated to Canadian dollars at the period-end foreign exchange rate and presented before unamortized transaction costs.

Forward-Looking Statements

Certain statements contained in this MD&A, including the documents incorporated by reference, may contain projections and "forward-looking statements" within the meaning of that phrase under Canadian and US securities laws. When used in this document, the words "may," "would," "could," "will," "intend," "plan," "anticipate," "believe," "estimate," "expect" and similar expressions may be used to identify forward-looking statements. Those statements reflect management's current views with respect to future events or conditions, including prospective results of operations, financial position, predictions of future actions or plans or strategies.

Certain material factors and assumptions were applied in drawing conclusions and making those forward-looking statements. By their nature, those statements reflect management's current views, beliefs and assumptions and are subject to certain risks and uncertainties, known and unknown, and assumptions, including, without limitation, production and development delays; changing environmental regulations; government and administrative decisions and changes to laws and regulations; the ability to attract and retain business partners; changes in material and construction costs; the ability to exploit hydrocarbon resources with existing technology; the ability to attract and retain key personnel; the need to obtain and maintain proprietary rights over technology; competition from other technologies; the ability of the Company and its joint venture partner to access the capital required for research, technology development, operations and marketing, resource delineation and project development; the need to generate positive cash flow in the foreseeable future; and changes in energy prices and currency levels.

Many factors could cause actual results, performance or achievements to be materially different from any future results, performance or achievements that may be expressed or implied by these forward-looking statements. Should one or more of these risks or uncertainties materialize, or should the assumptions underlying the projections or forward-looking statements prove incorrect, the actual results may vary materially from those described in this report as intended, planned, anticipated, believed, estimated, or expected. There is no intention and the reader should not assume any obligation to update these forward-looking statements, whether as a result of new information, plans, events or otherwise.

Additional Disclosure

The Company is not a reporting issuer, nor are its securities traded on any stock exchange in Canada. As a result, the Company is not subject to regulation by any Canadian stock exchange.

The Company's securities are also not registered under the United States Securities Act of 1933, nor are they traded on any securities or stock exchange in the United States. As a result, the Company is not presently subject to the reporting, certification or other requirements imposed on US registered issuers under, among other things, the US Sarbanes-Oxley Act of 2002.

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Report of Management

Management's Responsibility for the Financial Statements

The accompanying consolidated financial statements of Osum Oil Sands Corp. (the "Company") are the responsibility of management. The consolidated financial statements have been prepared by management in Canadian dollars in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and include certain estimates that reflect management's best judgments. Financial information contained throughout the annual report is consistent with these consolidated financial statements.

The Company maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that our internal controls over financial reporting were effective as of December 31, 2019.

The Company's Board of Directors has approved the consolidated financial statements. The Board of Directors fulfills its responsibility regarding the consolidated financial statements mainly through its Audit Committee which is composed of four directors, all of which are independent of management. The Audit Committee has a written mandate that complies with the current requirements of Canadian securities legislation. The Audit Committee meets with management at least on a quarterly basis to review and approve interim financial statements prior to their release as well as with management and the independent auditors annually to review annual financial statements and management's discussion and analysis and recommend their approval to the Board of Directors.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to audit and provide their independent audit opinion on the Company's consolidated financial statements as at and for the year ended December 31, 2019. Their report, contained herein, outlines the nature of their audit and expresses their opinion on the consolidated financial statements.

Steve Spence	Victor Roskey
President and Chief Executive Officer	Chief Financial Officer

March 26, 2020

Independent auditor's report

To the Shareholders of Osum Oil Sands Corp.

Our opinion

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

What we have audited

The Company's consolidated financial statements comprise:

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

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

Independence

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. We have fulfilled our other ethical responsibilities in accordance with these requirements.

Other information

Management is responsible for the other information. The other information comprises the information, other than the consolidated financial statements and our auditor's report thereon, included in the annual report.

PricewaterhouseCoopers LLP
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T: +1 403 509 7500, F: +1 403 781 1825

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 identified above 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.

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 IFRS, 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.
- Obtain sufficient appropriate audit evidence regarding the financial information of the entities or business activities within the Company to express an opinion on the consolidated financial statements. We are responsible for the direction, supervision and performance of the group audit. We remain solely responsible for our audit opinion.

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.

PricewaterhouseCoopers LLP

Chartered Professional Accountants

Calgary, Alberta
March 26, 2020

Osum Oil Sands Corp.

Consolidated Statements of Financial Position
(Expressed in thousands of Canadian dollars)

	December 31, 2019	December 31, 2018
Assets		
Current assets:		
Cash and cash equivalents	114,478	52,670
Restricted cash (note 6)	11,098	13,885
Accounts receivable	26,063	12,836
Prepaid expenses and other assets	2,035	1,856
Financial risk management contracts (note 7)	4,256	31,657
Total current assets	157,930	112,904
Non-current assets:		
Property, plant and equipment (note 8)	644,868	679,972
Exploration, evaluation and other intangible assets (note 9)	28,297	27,077
Abandonment deposits	398	360
Deferred tax asset (note 10)	63,280	56,906
Financial risk management contracts (note 7)	—	4,460
Total assets	**894,773**	**881,679**
Liabilities		
Current liabilities:		
Accounts payable, accrued liabilities and provisions (note 12)	22,925	18,328
Current portion of long-term debt (note 11)	42,833	2,865
Share unit liabilities (note 13)	5,284	4,083
Current portion of lease liabilities (note 18)	499	—
Financial risk management contracts (note 7)	20,268	9,649
Current portion of deferred consideration (note 17)	1,420	1,156
Total current liabilities	93,229	36,081
Non-current liabilities:		
Long-term debt (note 11)	178,688	268,052
Decommissioning liabilities (note 12)	48,657	44,132
Share unit liabilities (note 13)	2,820	2,420
Lease liabilities (note 18)	522	—
Deferred consideration (note 17)	66,048	62,892
Total non-current liabilities	296,735	377,496
Shareholders' equity		
Common shares (note 13)	1,035,592	1,032,554
Contributed surplus (note 13)	67,484	67,410
Cumulative deficit	(598,267)	(631,862)
Total shareholders' equity	504,809	468,102
Total liabilities and shareholders' equity	**894,773**	**881,679**

Contractual obligations and commitments (note 20)

The accompanying notes are an integral part of these consolidated financial statements.

Vincent Chahley
Director

George Crookshank
Director

Osum Oil Sands Corp.

Consolidated Statements of Net and Comprehensive Income
(Expressed in thousands of Canadian dollars, except share and per share amounts)

For the years ended December 31,	2019	2018
Revenue:		
Petroleum sales (note 16)	562,450	246,254
Deferred consideration (note 17)	2,787	5,991
Royalties	(24,808)	(10,783)
Revenue net of royalties	540,429	241,462
Gain (loss) on financial risk management contracts (note 7)	(96,594)	34,758
Revenue net of gain (loss) on financial risk management contracts	443,835	276,220
Expenses:		
Diluent and transportation	196,125	136,920
Product purchases (note 16)	32,115	4,944
Operating expenses	76,856	52,911
Curtailment allotment purchases	4,468	—
Depletion and depreciation (notes 8, 9)	58,125	36,191
Impairment reversal (note 8)	—	(135,525)
General and administrative expenses	12,940	12,660
Share-based compensation expense (note 13)	10,963	6,344
Total expenses	391,592	114,445
Other expenses (income):		
Net finance costs (note 19)	36,576	26,192
Unrealized foreign exchange loss (gain) on long-term debt	(12,427)	21,595
Accretion (note 12)	873	887
Total other expenses	25,022	48,674
Net income before taxes	**27,221**	**113,101**
Deferred income tax recovery (note 10)	(6,374)	(22,452)
Net and comprehensive income	**33,595**	**135,553**
Net income per share, basic and diluted (note 13)	$0.26	$1.03
Weighted average number of common shares outstanding (thousands) (note 13):		
Basic	131,626	131,009
Diluted	134,413	134,228

The accompanying notes are an integral part of these consolidated financial statements.

Osum Oil Sands Corp.

Consolidated Statements of Changes in Equity
(Expressed in thousands of Canadian dollars)

	Number of common shares (thousands)	Share capital	Contributed surplus	Cumulative deficit	Total equity
Balance – January 1, 2019	131,036	1,032,554	67,410	(631,862)	468,102
Net income	—	—	—	33,595	33,595
Share-based compensation	—	—	3,112	—	3,112
Share issuance on settlement of share units (note 13)	881	3,038	(3,038)	—	—
Balance – December 31, 2019	**131,917**	**1,035,592**	**67,484**	**(598,267)**	**504,809**
Balance – January 1, 2018	130,963	1,032,277	63,777	(767,415)	328,639
Net income	—	—	—	135,553	135,553
Share-based compensation	—	—	3,905	—	3,905
Share issuance on settlement of share units (note 13)	36	234	(234)	—	—
Reallocation on exercise of stock options and performance warrants (note 13)	37	43	(38)	—	5
Balance – December 31, 2018	**131,036**	**1,032,554**	**67,410**	**(631,862)**	**468,102**

The accompanying notes are an integral part of these consolidated financial statements. Refer to note 13 for further details on share capital.

Osum Oil Sands Corp.

Consolidated Statements of Cash Flows
(Expressed in thousands of Canadian dollars)

For the years ended December 31,	**2019**	**2018**
Cash provided by (used in)		
Operating activities:		
Net income for the period	33,595	135,553
Items not involving cash:		
Depletion and depreciation (notes 8, 9)	58,125	36,191
Impairment reversal (note 8)	—	(135,525)
Unrealized foreign exchange loss (gain) on long-term debt	(12,427)	21,595
Share-based compensation expense (note 13)	10,963	6,344
Amortization and derecognition of deferred transaction costs (notes 11, 19)	3,523	1,955
Accretion (note 12)	873	887
Interest expense – deferred consideration (notes 17, 19)	6,207	6,020
Change in fair value of financial risk management contracts (note 7)	42,480	(26,789)
Onerous contract recovery	—	(194)
Deferred income tax recovery (note 10)	(6,374)	(22,452)
Revenue – deferred consideration (note 17)	(2,787)	(5,991)
Settlements of onerous contract	(118)	(1,218)
Settlements of share unit liabilities (note 13)	(7,205)	(228)
Settlements of decommissioning liabilities (note 12)	(600)	(929)
Funds flow from operating activities before changes in non-cash working capital	126,255	15,219
Change in non-cash operating working capital (note 21)	(9,291)	4,514
Total cash flows from operating activities	**116,964**	**19,733**
Investing activities:		
Property, plant and equipment expenditures (note 8)	(16,993)	(165,700)
Investment in exploration, evaluation and other intangible assets (note 9)	(1,049)	(56)
Disposition of exploration, evaluation and other intangible assets (note 9)	110	—
Transaction costs on disposition of property, plant and equipment	—	(28)
Change in abandonment deposits	(35)	(24)
Change in non-cash investing working capital (note 21)	1,036	(15,079)
Total cash used in investing activities	**(16,931)**	**(180,887)**
Financing activities:		
Proceeds from share issuance	—	6
Principal repayments of long-term debt (note 11)	(38,552)	(2,760)
Debt issue costs (note 11)	(1,940)	—
Principal payments of lease liabilities (note 18)	(520)	—
Total cash used in financing activities	**(41,012)**	**(2,754)**
Increase (decrease) in cash in year	59,021	(163,908)
Cash and cash equivalents – beginning of year	52,670	217,007
Restricted cash – beginning of year	13,885	13,456
Cash and cash equivalents – end of year	**114,478**	**52,670**
Restricted cash – end of year	**11,098**	**13,885**

The accompanying notes are an integral part of these consolidated financial statements.

1. The Company

Osum Oil Sands Corp. (“Osum” or the "Company”) is a private company formed under the Alberta Business Corporations Act on June 24, 2005. The Company’s primary activities are the operation and development of its in-situ bitumen properties in Alberta, Canada. These annual consolidated financial statements encompass the Company and its wholly-owned subsidiaries, Osum Production Corp. (“OPC”) and Osum Holdings Corp. ("OHC").

The address of the Company’s head office is Suite 1900, 255-5th Avenue SW, Calgary, Alberta, Canada, T2P 3G6.

2. Basis of Preparation

These annual consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and Interpretations of the International Financial Reporting Interpretations Committee ("IFRIC"). These consolidated financial statements are presented in Canadian dollars ("C$"), the Company's functional currency, and all financial information is reported in thousands of dollars unless otherwise noted.

These consolidated financial statements reflect the activities of the Company and its wholly-owned subsidiaries. All intercompany transactions, balances, income and expenses have been eliminated on consolidation.

These consolidated financial statements were authorized for issue by the Board of Directors on March 26, 2020.

3. Significant Accounting Policies

(a) Joint operations

Some of the Company’s oil sands activities are conducted jointly with other entities. The consolidated financial statements reflect only the Company’s proportionate interest in such activities.

(b) Revenue recognition

Revenue from the sale of blended bitumen is measured based on the consideration specified in contracts with customers. The Company recognizes revenue upon satisfaction of its performance obligations, which is at the time the customer obtains legal title to the blended bitumen.

Crown royalties are recognized at the time of production. Gross overriding royalties are recognized when legal title of the blended bitumen is transfered. Realized risk management gains and losses are recognized in the related contract month.

Revenue associated with the recognition of deferred consideration related to the sale of a gross overriding royalty interest is recorded based on the actual capital expenditures, operating expenses, abandonment costs and crown royalties incurred in the period related to the royalty owner's share of production relative to the total of those forecast costs for the royalty owner's share of proved plus probable reserves. Forecast costs are as estimated in the most recent independent reserve engineering report, which is prepared at least annually.

(c) Accounts receivable

Accounts receivable relate primarily to blended bitumen sales and realized risk management gains receivable, which are recorded based on the Company's revenue recognition policy described above. The Company's maximum exposure to credit risk related to revenue and risk management contracts is considered to be inconsequential.

(d) Property, plant and equipment and exploration, evaluation and other intangible assets

(i) Recognition and measurement

Exploration, evaluation and other intangible assets

The Company accounts for exploration, evaluation and other intangible ("E&E") costs in accordance with the requirements of IFRS 6 “Exploration for and Evaluation of Mineral Resources”. Eligible costs of exploring for and evaluating oil sands properties are capitalized and the resulting E&E assets are disaggregated into project areas. Once a project area categorized as an E&E asset has been assigned proved and/or probable reserves and has, in management’s opinion, demonstrated commercial viability through the use of established technology, the asset is assessed for impairment and then transferred to property, plant and equipment ("PP&E"). When transferred from E&E, the associated assets are grouped into cash generating units ("CGUs"), which represent groups of assets that generate cash flows from continuing use, largely independent of cash flows from other assets or groups of assets.

E&E costs related to each licence or prospect are initially capitalized within E&E assets. Such E&E costs may include costs of licence acquisition, technical services and studies, seismic acquisition, exploration drilling and testing, pilot project costs, costs of retiring assets (if any) and directly attributable general and administrative ("G&A") costs, but do not include general prospecting or evaluation costs incurred prior to having obtained legal rights to explore the area, which are expensed directly in net income (loss) as they are incurred.

Tangible assets acquired for use in E&E activities are classified separately within E&E and other intangible assets and, once available for use, are depreciated based on their estimated useful life. To the extent that these assets are consumed as part of E&E activities, the associated depreciation is capitalized as part of the applicable E&E asset.

Intangible exploration assets are not depleted and are carried forward until technical feasibility and commercial viability of extracting a resource has been demonstrated.

Property, plant and equipment

Development and production items of PP&E are measured at cost less accumulated depletion, depreciation and impairment losses. Development and production assets are grouped into CGUs for impairment testing.

(ii) Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability of PP&E are recognized as capital investment only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures, including the costs of day-to-day maintenance of PP&E, are recognized in net income (loss) as incurred. Such capitalized investments generally represent costs incurred to develop proved or probable reserves to commence or enhance production from such reserves, and are accumulated on a field or area basis.

(iii) Depletion and depreciation

The net carrying values of producing oil and gas assets in PP&E are depleted using the unit of production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account estimated future development costs necessary to produce the reserves. Costs for plant turnarounds are depreciated over the period until the next planned turnaround.

Corporate assets in PP&E and tangible equipment available for use in E&E activities are depreciated over their estimated useful lives on a straight-line basis. These estimated useful lives for the current and comparative year are as follows:

Joint venture infrastructure at Saleski	30 years
Joint venture pilot facilities at Saleski	10 years
Capitalized geological and geophysical software	10 years
Office furniture & equipment	5 years
Computer hardware/software	3 years
Leasehold improvements	Term of lease

Other intangible assets held by the Company which have a finite useful life are amortized over that useful life and measured at cost less accumulated amortization. Depreciation methods, useful lives and residual values are reviewed at each reporting date.

(iv) Disposition of a gross overriding royalty interest

The proceeds from the sale of a gross overriding royalty interest are assessed to determine the portion that relates to (1) a payment for a partial disposal of an interest in PP&E; and (2) an upfront payment received for costs expected to be incurred by the Company in relation to future production of the royalty owner's share of proved plus probable reserves.

The portion of the proceeds representing the present value of estimated future costs in relation to the royalty owner's share of reserves at the time of the sale is recorded as deferred consideration and recognized in revenue in the manner described in note 3 (b).

The portion of the proceeds attributable to the disposal of PP&E is compared with the royalty share of the carrying amount of the property, and the resultant gain or loss is recorded in net income (loss).

(e) Impairment

(i) Financial assets

The Company recognizes loss allowances for expected credit losses ("ECLs") on its financial assets measured at amortized cost. The Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible defaults over the expected life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset.

(ii) Non-financial assets

The carrying amounts of the Company's non-financial assets are reviewed at each reporting date to determine whether there is any indication of impairment or that a previous impairment no longer exists. If any such indication exists, then the asset's recoverable amount is estimated.

E&E assets are assessed for impairment when they are reclassified to PP&E and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, PP&E assets are grouped into CGUs, the smallest group of assets that generates cash inflows from continuing use that are largely independent of cash flows of other assets or groups of assets. All E&E assets are assessed together as a grouped CGU. The recoverable amount is the higher of the fair value less costs to dispose and the value in use. As IFRS requires value in use estimates to be based on budgets and forecasts that generally extend no longer than five years, fair value less costs to dispose is used by the Company as it is the higher amount. In estimating fair value less costs to dispose, recent market transactions are taken into account, if available. In the absence of such transactions, an after-tax discounted cash flow model is used to estimate the fair value less costs to dispose of PP&E assets, while the recoverable amount of E&E assets is estimated using fair values per barrel of recoverable resource.

An impairment loss is recognized if the carrying amount of a CGU exceeds its estimated recoverable amount. Impairment losses are recognized in net income (loss). Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed only to the extent that the CGU's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(f) Foreign currency translation

The measurement and reporting currency of the Company is the Canadian dollar. Transactions of the Company that are denominated in foreign currencies are recorded in Canadian dollars at exchange rates in effect at the related transaction date. Monetary assets and liabilities denominated in foreign currencies are adjusted to reflect exchange rates at the end of the reporting period. Non-monetary assets, including related depreciation, are translated at historical rates. Exchange gains and losses arising on the translation of monetary assets and liabilities are included in the determination of net income (loss) for the period.

(g) Share-based compensation

The Company uses the fair value based method of accounting for share-based compensation for all awards of shares, performance warrants, stock options, restricted share units ("RSUs"), and performance share units ("PSUs") granted. For all awards expected to be settled in shares, compensation cost is recognized over the vesting period of the award based on the estimated fair value on the grant date with a corresponding increase to contributed surplus. Required tax withholdings on equity-settled awards are made by withholding equity instruments equal to the monetary value of the tax obligation, and are treated as equity-settled. Compensation cost for all share unit awards expected to be settled in cash is also recognized over the vesting period of the award but since the cash-settled portion of the awards is accounted for as a liability, its fair value is assessed and adjusted (if necessary) at each reporting period.

Management utilizes a graded vesting model to calculate compensation expense for all stock options granted. Since there is no progressive vesting associated with share unit awards, their compensation cost is recognized on a straight-line basis over the life of the awards. Management has incorporated an estimated forfeiture rate in its vesting models and, where appropriate, the Black-Scholes pricing model is used to estimate the fair value of an award on the date of grant. Proceeds received on the exercise of stock options and performance warrants are included in share capital.

(h) Deferred income taxes

Deferred income taxes are accounted for using the liability method. Under this method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted or substantively enacted income tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the year that the substantive enactment occurs.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity.

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

(i) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a risk-free rate that reflects current market assessments of the time value of money and the risks specific to the liability.

Some of the Company's activities give rise to decommissioning and site disturbance remediation activities. Provision is made for the estimated cost of site restoration and is capitalized in the relevant asset category. The Company may also recognize provisions for onerous contracts. An onerous contract is a contract in which the aggregate cost required to fulfill the agreement is higher than the economic benefit expected to be obtained from it.

Provisions are measured at the present value of management's best estimate of the expenditures required to settle the present obligation at the end of each reporting period. Subsequent to initial measurement, the obligation is adjusted utilizing the risk-free rate at the end of each reporting period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The increase in the provision due to the passage of time (accretion) is recognized as an expense, whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual expenditures incurred upon settlement of the obligation are charged against the provision to the extent the provision was established.

(j) Income (loss) per share

Basic income (loss) per share is calculated using the weighted average number of shares outstanding in the year. The Company uses the treasury stock method to calculate diluted income (loss) per share. Diluted income (loss) per share excludes the effect of all outstanding options and warrants that would be anti-dilutive.

(k) Comprehensive income (loss)

Comprehensive income (loss) is comprised of net income (loss) and other comprehensive income (loss) ("OCI"). The Company does not have any transactions that give rise to OCI; therefore, its net income (loss) and comprehensive income (loss) are the same amount.

(l) Financial instruments

Financial instruments, which are comprised of financial assets, financial liabilities, derivatives and non-financial derivatives, qualify as assets or liabilities and are recorded on the statement of financial position. Financial assets and financial liabilities are measured at fair value on initial recognition, which is typically the transaction price unless a financial instrument contains a significant financing component. Financial instruments are separated into three categories that determine their initial measurement and the subsequent recognition of gains and losses:

(i) Amortized cost – Includes cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, abandonment deposits, long-term debt and assets that are held with the objective of collecting contractual cash flows which by their terms give rise on specified dates to cash flows that represent solely payments of principal and interest. The financial assets and financial liabilities in the category are measured at amortized cost using the effective interest method.

Financial liabilities are derecognized when the liability is extinguished. A substantial modification of the terms of an existing financial liability is recorded as an extinguishment of the original financial liability and the recognition of a new financial liability. Where a modification is treated as an extinguishment, any unamortized deferred transaction costs associated with the extinguished financial liability, along with any premiums, discounts or financing costs incurred at the time of the modification, are recognized immediately in net income (loss). Transaction costs that are directly attributable to the new liability such as legal expenses and arrangement fees are deferred and amortized over the term of the new financial liability.

(ii) Fair value through other comprehensive income ("FVOCI") – Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, which by their terms give rise on specified dates to cash flows that represent solely payment of principal and interest. The Company has not designated any financial instruments as FVOCI.

(iii) Fair value through profit or loss ("FVTPL") – Includes assets that do not meet the criteria for amortized cost or FVOCI such as financial risk management contracts and share unit liabilities. The financial assets and liabilities in this category are measured at fair value and changes are recorded in profit or loss.

The Company's financial risk management contracts are derivative instruments, but are not used for trading or speculative purposes. The Company has not designated its financial risk management contracts as effective accounting hedges, and thus has not applied hedge accounting, even though the Company considers the contracts to be economic hedges. Financial risk management contracts are designated as FVTPL and therefore are recognized initially at fair value and any attributable transaction costs are recognized in net income (loss) when incurred. Subsequent to initial recognition, financial risk management contracts are measured at fair value, and changes therein are recognized immediately in net income (loss).

Financial assets and liabilities are classified as current if payment is due within twelve months. Otherwise, they are presented as non-current.

(m) Leases

Policy applicable from January 1, 2019

The Company assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration.

A lease liability is recognized at the commencement of the lease term at the present value of the lease payments that have not been paid at that date. These payments are discounted using the Company's estimated incremental borrowing rate when the rate implicit to the lease is not readily available. At the commencement date, a corresponding right-of-use ("ROU") asset is recognized at the amount of the lease liability, adjusted for lease incentives received, retirement costs and initial direct costs. Depreciation is recognized on the ROU asset over the shorter of the estimated useful life of the asset or the lease term. Interest expense is recognized on the lease liabilities using the effective interest rate method and payments are applied against the lease liabilities.

Leases that have terms of less than twelve months or leases on which the underlying asset is of low value are recognized as an expense in the consolidated statement of comprehensive income (loss) on a straight-line basis over the lease term.

Policy applicable before January 1, 2019

Leases in which substantially all of the risks and rewards of ownership were retained by the lessor were classified as operating leases. Operating lease payments were recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership were classified as finance leases. At inception, a leased asset and a corresponding lease obligation were recognized. The leased asset was depreciated over the shorter of the estimated useful life of the asset or lease term.

4. Critical Accounting Estimates

The timely preparation of financial statements in accordance with IFRS requires management to make estimates and judgments that affect the reported amounts of assets and liabilities and disclosure of contingencies at the dates of the annual consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. The estimated fair value of assets and liabilities, by their very nature, are subject to measurement uncertainty. Accordingly, actual results may differ materially from estimated amounts as future confirming events occur. Significant judgments, estimates and assumptions made by management in the preparation of these consolidated financial statements are outlined below.

Sale of a royalty interest

When the Company sells a royalty interest linked to production at a specific property, judgment is required in assessing the appropriate accounting treatment of the transaction on the closing date and in future periods. The Company considers the specific terms of the arrangement to determine whether it has entered into a financing arrangement, disposed of an interest in the reserves of a property, and/or received an upfront payment for future services. This assessment considers the economic substance of the arrangement including the Company's method of settlement, the risks assumed by the royalty owner, the duration of the arrangement, the property or properties to which the royalty applies, the timing of the royalty owner's investment including any potential future payments, any penalties for the Company failing to deliver the royalty, the royalty owner's involvement in the Company's ongoing decision-making, and any commitments made by the Company to develop future expansions or projects at the property. To the extent it is determined that there is an upfront payment for future services, judgment is required to estimate the value of such services.

Bitumen reserves and resource

The estimation of reserves and resource involves the exercise of judgment. Forecasts are based on engineering data, estimated future prices, expected future rates of production and the cost and timing of future capital and operating expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserves estimates will be revised either upward or downward based on updated information such as the results of future drilling, testing and production. Reserves and resource estimates can have a significant impact on net income (loss), as they are key components in the calculations of depletion and deferred consideration and for determining potential asset impairment or reversals thereof. Reserves and resource estimates for properties in PP&E are prepared by independent reserve engineers at least annually. Independently prepared resource estimates for E&E properties may be prepared less frequently but at minimum are reviewed and, if necessary, updated by management annually.

Financial risk management contracts

The fair value of financial risk management contracts is dependent on estimates of forward commodity prices, differentials and foreign exchange rates. While forward prices and rates at the balance sheet date were determined based on observable market data, they will likely differ from future prices and rates and significantly impact the fair value of financial risk management contracts.

Carrying value of exploration and evaluation assets

The application of the Company's accounting policy for E&E expenditures requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined and when technical feasibility and commercial viability have been reached. Estimates and assumptions may change as new information becomes available.

Leases

The Company uses judgment when assessing all contracts to determine if the contract contains a lease. Contracts identified as containing a lease are subject to further judgment and estimation to determine the lease term and discount rate. The Company considers relevant economic and operational factors when deciding to include extension options in the lease term. When the implicit discount rate of a lease is not available, lease liabilities are estimated using a discount rate similar to the Company's incremental borrowing rate.

Identification of cash generating units

CGUs are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash inflows of other assets or groups of assets. The classification of assets into CGUs requires significant judgment and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructures, and the way in which management monitors the Company's operations.

Provisions

Provisions are recognized for the future decommissioning and restoration of the Company's oil and gas assets to be incurred at the end of their economic life. The reported amount of the obligation is based on estimated future costs for the abandonment of the assets and reclamation of the site to its original state discounted at a risk-free rate and must be reevaluated each reporting period. Estimating the timing, amount and present value of these retirement costs requires significant judgment. By their nature, these estimates, as they become available, are subject to measurement uncertainty, and the impact on the consolidated financial statements could be material.

The Company recognizes a provision relating to its head office lease equal to the present value of the difference between the minimum future lease payments that the Company is obligated to make under the lease until its expiry, including estimated future operating costs, less estimated sublease recoveries. Actual recoveries and operating costs may differ significantly from these estimates.

In addition, the Company makes estimates of potential provisions owing within accounts payable, accrued liabilities and provisions which may include amounts disputed in the normal course of business. Amounts ultimately paid may differ significantly from these estimates.

Share-based compensation

The Company uses a fair value-based method of accounting for share-based compensation for all awards of shares, performance warrants, stock options, RSUs and PSUs. The Black-Scholes pricing model is used to estimate the fair value of stock options and performance warrants on the date of grant. The Black-Scholes pricing model includes inputs such as discount rates, expected exercise dates, and expected volatility, which are subject to judgment and may not be indicative of future experience. Into its vesting models, management has incorporated an estimated forfeiture rate, which is also subject to judgment. The liability for the portion of share unit awards that is expected to be settled in cash is based on an estimate of the Company's share price at the reporting date established by the Company's board of directors after considering a third-party estimate of fair value and an assumption that staff will elect to receive the maximum cash award. As the Company is a private entity, its estimated share price is subject to significant judgment.

Deferred income taxes

The determination of deferred income tax assets and liabilities requires interpretation of complex laws and regulations, and they are recognized at tax rates expected to be in effect at the estimated timing of reversal of temporary differences between the accounting and tax treatment of certain assets and liabilities. To the extent these judgments change, there may be a significant impact on the consolidated financial statements of future periods.

Deferred income tax assets are recognized to the extent that it is probable that the deductible temporary differences will be recoverable in future periods. The recoverability assessment involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an estimation of the amount of future taxable earnings, the availability of taxable income to offset the tax assets when the reversal occurs and the application of tax laws. To the extent that assumptions used in the recoverability assessment change, there may be a significant impact on the consolidated financial statements of future periods.

(Expressed in thousands of Canadian dollars)

5. Changes in Accounting Standards

IFRS 16 – Leases

Effective January 1, 2019, the Company adopted IFRS 16, "Leases". The Company applied the new standard using the modified retrospective approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect as an adjustment to the opening retained earnings and applies the standard prospectively. Therefore, the comparative information in the Company's consolidated statements of financial position, net and comprehensive income (loss), shareholders' equity and cash flows were not restated.

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

- Apply a single discount rate to a portfolio of leases with similar characteristics;
- Account for lease payments as an expense and not recognize a ROU asset if the underlying asset is of a low dollar value (less than US$5 thousand) or has a remaining term of less than twelve months as at January 1, 2019;
- Utilize hindsight to determine the appropriate lease term where the contract contains terms to extend or terminate the lease.

On adoption of IFRS 16, the Company recognized lease liabilities in relation to leases which had been previously classified as operating leases under the principles of IAS 17, "Leases". Under the principles of the new standard these leases were measured at the present value of the remaining lease payments, discounted using the Company's estimated incremental borrowing rate at January 1, 2019. Leases with a remaining term of less than twelve months and low-value leases were excluded. As at January 1, 2019, the Company recognized total lease liabilities of $1,306, of which $518 were classified as current. The associated ROU assets were measured at the amount equal to the lease liabilities.

Reconciliation to operating lease commitments at December 31, 2018:

Operating lease commitments – December 31, 2018	3,586
Less:	
Agreements that do not contain a lease	(232)
Short term leases not in IFRS 16 scope	(435)
Non-lease components	(1,657)
Add:	
Lease liabilities in scope under IFRS 16	204
Undiscounted lease liabilities – December 31, 2018	1,466
Impact of discounting	(160)
Lease liabilities – January 1, 2019	1,306

The Company assessed the transportation agreements in the commitments note as at December 31, 2018 and concluded that they were not within the scope of IFRS 16 as the Company did not control the related assets.

(Expressed in thousands of Canadian dollars)

6. Restricted Cash

As at December 31, 2019, the Company had pledged $11,098 (December 31, 2018 – $13,885) in Guaranteed Investment Certificates as security for letters of credit in support of ongoing business operations and contractual commitments.

7. Financial Risk Management Contracts

The Company recorded the following net gains (losses) related to its financial risk management contracts:

For the years ended December 31,	2019	2018
Realized net gain (loss)	(54,114)	7,969
Change in fair value	(42,480)	26,789
Net gain (loss) on financial risk management contracts	(96,594)	34,758

The following table summarizes the financial risk management contracts that were in place as at December 31, 2019. All contracts were fixed price swaps in Canadian dollars. The related fair values were recorded on the consolidated statement of financial position:

	2020				
WTI	Q1	Q2	Q3	Q4	Total
bbl/d	8,840	7,750	8,850	8,850	
Avg. price ($/bbl)	76.96	74.32	73.62	73.47	
Fair value	(1,432)	(1,860)	(1,001)	264	(4,029)
WTI-WCS differential					
bbl/d	11,920	10,450	12,000	12,000	
Avg. price ($/bbl)	(28.72)	(28.08)	(26.97)	(27.23)	
Fair value	(867)	(4,783)	(5,193)	(4,469)	(15,312)
WTI-Condensate differential					
bbl/d	3,100	2,700	3,100	3,100	
Avg. price ($/bbl)	(5.90)	(5.97)	(5.93)	(5.94)	
Fair value	2,213	621	(309)	(9)	2,516
AECO gas					
GJ/d	11,150	9,500	11,150	11,150	
Avg. price ($/GJ)	1.67	1.58	1.57	1.62	
Fair value	372	11	109	321	813
Total fair value	286	(6,011)	(6,394)	(3,893)	(16,012)

At December 31, 2018, the Company had a net risk management asset of $26,468, comprised of an asset relating to WTI differential swaps of $33,900, a liability relating to WTI-WCS differential swaps of $8,123, an asset relating to WTI-Condensate differential swaps of $1,364 and a liability relating to AECO gas swaps of $673.

The fair value measurements are categorized as level 2 as they are based on quoted prices from independent pricing services in active markets for similar assets or liabilities.

(Expressed in thousands of Canadian dollars)

The following table sets out the impact of changes in forward commodity prices on net income (loss) before taxes related to changes in the fair value of financial risk management contracts in place as at December 31, 2019:

Price or rate	Change	Impact on net income (loss) before taxes
WTI	$1.00/bbl	3,138
WTI/WCS differential	$1.00/bbl	4,244
WTI/Condensate differential	$1.00/bbl	1,098
AECO gas	$0.05/GJ	197

Subsequent to December 31, 2019, the Company entered into financial risk management contracts with the following terms:

WTI	Q3 2020	Q1 2021
bbl/d	1,870	4,600
Average price ($/bbl)	42.84	63.80
WTI-WCS differential		
bbl/d	2,505	7,900
Average price ($/bbl)	(20.80)	(25.88)
WTI-Condensate differential		
bbl/d	615	1,950
Average price ($/bbl)	(5.64)	(4.73)
AECO gas		
GJ/d	—	6,000
Average price ($/GJ)	—	2.21

Credit and counterparty concentration risks related to the financial risk management contracts are considered acceptable due to the size and strength of the counterparties.

(Expressed in thousands of Canadian dollars)

8. Property, Plant and Equipment

	Development and production assets	Corporate assets	Total
Cost			
Balance – December 31, 2018	850,272	5,554	855,826
Additions	14,375	186	14,561
ROU assets recorded upon adoption of IFRS 16	626	680	1,306
ROU asset additions	235	—	235
Capitalized general and administrative expenses	2,432	—	2,432
Capitalized share-based compensation	954	—	954
Changes to decommissioning assets	3,513	—	3,513
Balance – December 31, 2019	**872,407**	**6,420**	**878,827**
Accumulated depletion and depreciation			
Balance – December 31, 2018	(170,646)	(5,208)	(175,854)
Depletion and depreciation	(57,767)	(338)	(58,105)
Balance – December 31, 2019	**(228,413)**	**(5,546)**	**(233,959)**
Carrying amounts			
Balance – December 31, 2018	679,626	346	679,972
Balance – December 31, 2019	**643,994**	**874**	**644,868**

(Expressed in thousands of Canadian dollars)

	Development and production assets	Corporate assets	Total
Cost			
Balance – December 31, 2017	674,541	5,372	679,913
Additions	162,493	182	162,675
Capitalized general and administrative expenses	3,025	—	3,025
Capitalized share-based compensation	812	—	812
Changes to decommissioning assets	9,401	—	9,401
Balance – December 31, 2018	**850,272**	**5,554**	**855,826**
Accumulated depletion, depreciation and impairment			
Balance – December 31, 2017	(270,097)	(5,112)	(275,209)
Depletion and depreciation	(36,074)	(96)	(36,170)
Impairment reversal	135,525	—	135,525
Balance – December 31, 2018	**(170,646)**	**(5,208)**	**(175,854)**
Carrying amounts			
Balance – December 31, 2017	404,444	260	404,704
Balance – December 31, 2018	**679,626**	**346**	**679,972**

During the year ended December 31, 2019, the Company recorded $57,010 (2018 – $35,616) of depletion, $472 (2018 – $458) of depreciation related to its Orion oil sands project, $484 (2018 – $0) of depreciation related to right-of-use assets and $139 (2018 – $117) related to corporate assets. The Company included $869,197 of future development costs associated with proved plus probable reserves in its depletion calculation for the period ended December 31, 2019 (2018 – $932,000).

Impairment Assessments

During 2019 the Company observed a decline in the average long-term price forecasts of a number of reserve engineering firms. The Company considered the price forecast decline an indicator of impairment for its Taiga CGU and performed an impairment test at December 31, 2019.

(Expressed in thousands of Canadian dollars)

The Company estimated the recoverable amount of its Taiga CGU based on fair value less costs of disposal calculations. The fair value of the CGU was estimated based on the present value of after-tax cash flows resulting from production from proved and probable reserves from 2020 to 2069 using assumptions consistent with those used by the Company's independent reserve evaluator, including capital and operating cost estimates, corporate tax rates, and a cost inflation factor of two percent, and using an after-tax discount rate of 12%. The following forward prices and foreign exchange rates were used to estimate the recoverable amount as at December 31, 2019:

Year	Western Canadian Select (C$/bbl)	WTI at Cushing (US$/bbl)	Diluent (condensate) (C$/bbl)	AECO gas (C$/mmbtu)	Exchange rate (US$/C$)
2020	56.66	60.25	74.21	2.05	0.760
2021	61.20	63.11	78.15	2.32	0.768
2022	63.08	66.02	80.48	2.60	0.784
2023	64.92	67.64	82.77	2.74	0.789
2024	66.54	69.16	84.66	2.82	0.789
2025	68.16	70.69	86.56	2.91	0.789
2026	69.80	72.25	88.49	2.97	0.789
2027	71.41	73.77	90.40	3.03	0.789
2028	72.94	75.25	92.22	3.10	0.789
Remainder	+2.0% per year	+2.0% per year	+2.0% per year	+2.0% per year	0.789

Source: Average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule Associates and Deloitte Research Evaluation & Advisory price forecasts, effective January 1, 2020.

Based on the calculations performed, the estimated recoverable amount of the Taiga CGU exceeded its carrying value and no impairment was recorded at December 31, 2019.

For the year ended December 31, 2019, an increase to the after-tax discount rate used in the Company's impairment test of 2% or a US$2 decrease to the WTI price would not have resulted in an impairment charge.

At December 31, 2019 and December 31, 2018, the Company did not observe any indicators of impairment with respect to its Orion CGU.

In its December 31, 2018 independent reserve evaluator's report, the Company observed a decrease in the forecast construction and drilling and completion costs for the Taiga CGU. The revised cost estimates were based on the Company's costs incurred for the Orion Phase 2BC expansion and drilling of 18 wells pairs. The Company considered the significant decrease in future development costs as an indicator of impairment reversal for the Taiga CGU and performed an impairment test at December 31, 2018.

The Company estimated the recoverable amount of its Taiga CGU based on fair value less costs of disposal calculations. The fair value of the CGU was estimated based on the present value of after-tax cash flows resulting from production from proved and probable reserves from 2019 to 2063 using assumptions consistent with those used by the Company's independent reserve evaluator, including capital and operating cost estimates, corporate tax rates, and a cost inflation factor of two percent, and using an after-tax discount rate of 12%.

(Expressed in thousands of Canadian dollars)

The following forward prices and foreign exchange rates were used to estimate the recoverable amount as at December 31, 2018:

Year	Western Canadian Select (C$/bbl)	WTI at Cushing (US$/bbl)	Diluent (condensate) (C$/bbl)	AECO gas (C$/mmbtu)	Exchange rate (US$/C$)
2019	51.16	58.44	71.49	1.85	0.758
2020	59.13	63.75	79.33	2.28	0.776
2021	64.62	67.28	84.05	2.68	0.790
2022	67.57	70.50	87.17	2.99	0.790
2023	70.82	73.54	90.68	3.21	0.800
2024	72.54	75.27	92.70	3.37	0.805
2025	74.38	77.03	94.87	3.51	0.806
2026	76.36	78.90	97.22	3.59	0.806
2027	77.98	80.49	99.19	3.68	0.806
Remainder	+2.0% per year	+2.0% per year	+2.0% per year	+2.0% per year	0.806

Source: Average of GLJ Petroleum Consultants, McDaniel & Associates Consultants, Sproule Associates and Deloitte Research Evaluation & Advisory price forecasts, effective January 1, 2019.

At December 31, 2018 the estimated recoverable amount of the Taiga CGU exceeded the carrying value and the full impairment charge recorded in 2017 on the Taiga CGU of $135,525 was reversed.

The fair value measurements are categorized as level 3 with inputs that are not based on observable market data.

9. Exploration, Evaluation and Other Intangible Assets

	Exploration and evaluation assets	Other Intangible assets	Total
Cost			
Balance – December 31, 2018	482,404	416	482,820
Additions	1,049	—	1,049
Capitalized depreciation	1,506	—	1,506
Changes to decommissioning assets	302	—	302
Disposition	(110)	—	(110)
Balance – December 31, 2019	**485,151**	**416**	**485,567**
Accumulated depreciation and impairment			
Balance – December 31, 2018	(455,450)	(293)	(455,743)
Depreciation	(1,506)	(21)	(1,527)
Balance – December 31, 2019	**(456,956)**	**(314)**	**(457,270)**
Carrying amounts			
Balance – December 31, 2018	26,954	123	27,077
Balance – December 31, 2019	**28,195**	**102**	**28,297**

(Expressed in thousands of Canadian dollars)

	Exploration and evaluation assets	Other Intangible assets	Total
Cost			
Balance – December 31, 2017	481,457	416	481,873
Capitalized depreciation	1,473	—	1,473
Capitalized general and administrative expenses	56	—	56
Capitalized share-based compensation	9	—	9
Changes to decommissioning assets	(591)	—	(591)
Balance – December 31, 2018	**482,404**	**416**	**482,820**
Accumulated depreciation and impairment			
Balance – December 31, 2017	(453,977)	(272)	(454,249)
Depreciation	(1,473)	(21)	(1,494)
Balance – December 31, 2018	**(455,450)**	**(293)**	**(455,743)**
Carrying amounts			
Balance – December 31, 2017	27,480	144	27,624
Balance – December 31, 2018	**26,954**	**123**	**27,077**

During the year ended December 31, 2019, the Company disposed of exploration, evaluation and other intangible assets for cash proceeds of $110.

Impairment Assessments

The Company's E&E assets are comprised of its Saleski Joint Venture, Saleski West, Sepiko Kesik, and Liege properties, located in the Saleski area and its Portage property located in the Athabasca area.

At December 31, 2019 and December 31, 2018, the Company did not observe any indicators of impairment or impairment reversal with respect to its E&E assets.

10. Deferred Taxes

The Company’s net deferred tax asset resides in the OPC legal entity and is comprised of the following, which are classified by source of temporary differences:

	December 31, 2019	December 31, 2018
Non-capital losses	95,403	110,173
Petroleum & natural gas properties	(52,911)	(52,316)
Decommissioning liabilities	785	690
Risk management contracts	3,812	(7,146)
Deferred consideration	16,067	17,300
Lease liabilities	124	—
Unrecognized deferred tax assets	(5,395)	(19,592)
Unrealized foreign exchange on account of capital	5,395	7,797
Deferred tax asset	63,280	56,906

(Expressed in thousands of Canadian dollars)

The Company also had the following temporary differences in the Osum Oil Sands Corp. legal entity for which no deferred tax asset was recognized:

	December 31, 2019	December 31, 2018
Non-capital losses	135,986	173,696
Petroleum & natural gas properties	(13,025)	(11,382)
Decommissioning liabilities	1,766	1,633
Onerous lease liability	—	118
Scientific research and experimental development ("SRED")	131,754	131,754
SRED investment tax credit	18,106	18,106
Lease liabilities	502	—
Total unrecognized temporary differences	275,089	313,925

As at December 31, 2019, the Company had approximately $1,068,726 (December 31, 2018 – $1,182,661) in consolidated available tax pools, including operating loss carry forwards of $535,910 (December 31, 2018 – $581,745) which are available to offset future taxable income. These operating losses start to expire in 2031.

The provision for income taxes reported differs from the amounts computed by applying the cumulative federal and provincial income tax rates to the income before tax provision due to the following:

For the years ended December 31,	2019	2018
Income (loss) before income taxes	27,221	113,101
Statutory tax rate	26.5%	27%
	7,214	30,537
Permanent differences	(1,640)	2,922
Stock based compensation	2,905	1,713
Alberta tax rate change	20,432	—
True up of tax provision to tax return	(19)	211
Change in unrecognized deferred tax assets	(34,950)	(58,111)
Other	(316)	276
Deferred tax recovery	(6,374)	(22,452)

The Canadian statutory tax rates from the rate reconciliation above represent the combined federal and provincial corporate tax rates. The federal corporate tax rate is 15.0% and the Alberta provincial tax rate was 12.0% until July 1, 2019 when it was reduced to 11.0%. The Alberta provincial tax rate will continue to decrease 1.0% annually on January 1st until it reaches 8.0% on January 1, 2022.

(Expressed in thousands of Canadian dollars)

11. Long-term Debt

Effective June 30, 2019, the Company's wholly-owned subsidiary, OPC, completed an amendment of its senior secured first lien term loan. As a result of the amendment:

- OPC made principal and amortization payments totaling US$10,525 at closing;
- US$172,120 of the term loan was extended by two years to July 31, 2022 (the "2022 Loans"); and
- US$17,905 of the term loan continued to have a maturity date of July 31, 2020 (the "2020 Loans").

The interest rate on the 2022 Loans varies between LIBOR plus 7.5% and 9.5% per annum depending on OPC's ratio of senior secured loans to earnings before interest, taxes and depreciation ("EBITDA"). The 2020 Loans continue to bear interest at LIBOR plus 5.5% per annum.

Depending on OPC's ratio of senior secured loans to EBITDA, 75% to 90% of OPC's cash flow in excess of deemed maintenance and sustaining capital spending is subject to a quarterly cash sweep that is applied against the principal balances of the loans.

Total required amortization of US$525 per quarter is unchanged. However, any principal repaid as a result of the cash sweep offsets future required payments in the order of scheduled maturity.

Principal repaid through amortization and the cash sweep is applied pro rata to the 2020 and 2022 Loans outstanding.

As the terms and expected cash flows of the 2022 Loans were substantially modified from those of the original term loan, the Company accounted for the amendment of the 2022 Loans under IFRS 9 as an extinguishment of a financial liability and the establishment of a new financial liability. As such, on the June 30, 2019 amendment date, US$172,120 of the term loan and the related pro rata portion of unamortized deferred debt issue costs of $2,130 were derecognized. A new financial liability of US$172,120 representing the 2022 Loans was recorded and the associated debt issue costs of $1,940 were deferred.

On September 25, 2019, OPC completed an amendment to extend the maturity date of its US$15,000 senior secured first lien revolving loan by two years to April 30, 2022.

A summary of the senior credit facilities balances is shown below:

	December 31, 2019	December 31, 2018
Senior secured revolving loan – US$	—	—
Senior secured term loan – US$	171,908	201,075
Total senior secured loans – US$	171,908	201,075
Period end exchange rate – US$1 = C$	1.2990	1.3641
Total senior secured loans – C$	223,308	274,286
Less: unamortized deferred debt issue costs	(1,787)	(3,369)
	221,521	270,917
Less: current portion of long-term debt	(42,833)	(2,865)
Long-term debt	178,688	268,052

(Expressed in thousands of Canadian dollars)

During the year ended December 31, 2019, OPC made principal repayments totaling US$29,167 or C $38,552 (2018 – US$2,100 or C$2,760) on the term loans. During the year ended December 31, 2019, $1,940 (2018 – $0) of debt issue costs were incurred, $2,130 (2018 – $0) of previously deferred debt issue costs related to the extinguished loans were derecognized and $1,392 (2018 – $1,955) of deferred debt issue costs were amortized against the loan balances.

Under the terms of the cash sweep, based on the results for the three months ended December 31, 2019, OPC is required to prepay US$18,753 of the principal balance of the term loans in the first quarter of 2020. This amount and the outstanding principal balance of the 2020 Loans due on July 31, 2020 are classified as a current liability at December 31, 2019.

The estimated fair market value of the loans as at December 31, 2019 approximated their carrying value. The estimated fair market value of the term loan at December 31, 2018 was $257,099, compared with a carrying amount of $274,286. The fair market value measurement of the loans at December 31, 2019 is categorized as level 3 as it is based on unobservable inputs.

The revolving loan was undrawn as at December 31, 2019 and December 31, 2018.

The senior secured loans are subject to covenants by OPC, including maintaining minimum ratios of asset values to net senior secured debt. OPC was in compliance with all loan covenants as at December 31, 2019 and December 31, 2018.

12. Decommissioning Liabilities

For the years ended December 31,	2019	2018
Balance – beginning of year	44,925	36,176
Liabilities incurred	—	5,839
Liabilities settled	(600)	(929)
Changes to discount rates	4,863	688
Changes in estimates	(1,048)	2,283
Accretion	873	868
Balance – end of year	49,013	44,925

As at December 31, 2019, the Company estimated that the expenditures required to settle the decommissioning liabilities will be made over the next 36 years with the majority of payments being made around 2045. As at December 31, 2019, the Company used discount rates ranging from 1.7% to 1.8% (December 31, 2018 – 1.9% to 2.2%) based on the Bank of Canada’s risk-free bond rates and an inflation rate of 1.4% (December 31, 2018 – 1.4%) to calculate the present value of the decommissioning liabilities.

At December 31, 2019, of the total decommissioning liability of $49,013 (December 31, 2018 – $44,925), $356 (December 31, 2018 – $793) was recorded as current within accounts payable, accrued liabilities and provisions and $48,657 (December 31, 2018 – $44,132) was recorded as non-current.

13. Share Capital

(a) Authorized

Unlimited number of voting common shares without nominal or par value.

(b) Stock options

During the year ended December 31, 2019, the Company's Board of Directors approved the issuance of 462,900 (2018 – 578,200) stock options to officers, directors, employees and contractors. The stock options expire six years from the grant date and vest in four equal tranches: 25% on the grant date and 25% on each of the three subsequent anniversary dates. A weighted average fair value of $1.39 (2018 – $1.13) per stock option was estimated on the grant date based on the following assumptions:

For the years ended December 31,	2019	2018
Share price on grant date	$3.10	$2.50
Exercise price	$3.10	$2.50
Expected volatility	50%	50%
Expected life	5 years	5 years
Risk-free interest rate (weighted average)	1.64%	2.04%
Expected forfeiture rate	12%	12%

A summary of the changes in options outstanding under the stock option plan is as follows:

	For the years ended			
	December 31, 2019		December 31, 2018	
	Number of options (000s)	Weighted average exercise price	Number of options (000s)	Weighted average exercise price
Balance – beginning of year	5,803	2.46	5,555	2.68
Granted	463	3.10	578	2.50
Exercised	—	—	(25)	0.15
Forfeited or expired	(181)	3.00	(305)	6.77
Balance – end of year	6,085	2.49	5,803	2.46

(Expressed in thousands of Canadian dollars)

The following is a summary of the number of stock options outstanding and exercisable as at December 31, 2019:

Exercise price	Number outstanding (thousands)	Exercisable (thousands)	Weighted average remaining life
$0.15	50	50	1.0 years
$1.00	25	25	1.0 years
$2.25	4,311	4,173	2.3 years
$2.50	571	285	4.2 years
$3.00	564	564	1.0 years
$3.10	463	116	5.2 years
$8.11	25	25	1.0 years
$9.00	76	76	1.8 years
	6,085	5,314	2.6 years

(c) Performance warrants

During the year ended December 31, 2018, the remaining 11,895 performance warrants were exercised at a price of $0.15 per performance warrant for proceeds of $2.

(d) RSUs and PSUs

During the year ended December 31, 2019, the Company issued 559,700 (2018 – 685,700) RSUs and 897,400 (2018 – 1,114,400) PSUs to employees, directors and contractors of the Company. The RSUs and PSUs granted vest all at once on the third anniversary date. The number of PSUs that ultimately vest is subject to the Company satisfying certain performance criteria within a target range set by the Company's Board of Directors. A multiplier (ranging from 0.5 to 2.0) will be applied to any vested PSUs to the extent such performance criteria are satisfied. The performance factor for the PSUs granted in the period was assumed to be 1.0 on the grant date.

Notwithstanding the Board's discretion to settle vested units in cash or with shares, according to the terms of the share unit plan, a unitholder may elect to receive up to 50 percent of their vested units in the form of a cash payment. The Company therefore treats the share units 50% equity-settled and 50% cash-settled.

A summary of the changes in RSUs and PSUs outstanding is as follows:

For the years ended December 31,	2019		2018	
(thousands)	RSUs	PSUs	RSUs	PSUs
Balance – beginning of year	2,371	3,990	1,805	2,941
Granted	560	897	686	1,114
Forfeited	(138)	(79)	(72)	(30)
Vested and settled	(940)	(1,761)	(48)	(35)
Balance – end of year	1,853	3,047	2,371	3,990

As at December 31, 2019, the Company's share unit liabilities for those RSUs and PSUs expected to be settled in cash were recorded using an estimated fair value of $4.40 per share unit (December 31, 2018 – $3.10) and performance factors for the PSUs ranging from 1.0 to 1.7 (December 31, 2018 – 1.0 to 1.3).

(Expressed in thousands of Canadian dollars)

As at December 31, 2019, $5,284 of the Company's share unit liabilities were classified as current (December 31, 2018 – $4,083), relating to those RSUs and PSUs scheduled to vest and be settled in cash in the next twelve months, while $2,820 (December 31, 2018 – $2,420) were classified as non-current.

As at December 31, 2019 using the same assumptions for share units that vest and are equity-settled, the Company estimated that it would pay $4,430 in tax withholdings, of which $2,218 were expected to be incurred in the next 12 months. Such amounts are included in the Company's commitments in note 20.

During the year ended December 31, 2019, 939,735 RSUs and 1,760,820 PSUs were settled which resulted in the issuance of 880,793 shares and $7,205 of cash payments, including payroll withholdings. The RSUs and PSUs were settled 50% in cash and 50% in shares with a PSU performance factor of 1.29.

On March 26, 2020 the Company's Board of Directors approved a grant of up to 371,600 RSUs and 1,050,000 PSUs to employees, directors and contractors.

(e) Contributed surplus

The table below summarizes activity in the contributed surplus account (excludes share-based compensation associated with share units expected to be settled in cash, which is reported as a liability on the consolidated statements of financial position):

For the years ended December 31,	2019	2018
Balance – beginning of year	67,410	63,777
Share-based compensation	3,112	3,905
Share units settled	(3,038)	(234)
Stock options and performance warrants exercised	—	(38)
Balance – end of year	67,484	67,410

(Expressed in thousands of Canadian dollars)

(f) Per share amounts

The table below summarizes the weighted average number of common shares outstanding used in the calculation of basic and diluted income per common share:

(thousands) For the years ended December 31,	2019	2018
Weighted average common shares outstanding	131,626	131,009
Effect of dilutive securities	2,787	3,219
Weighted average common shares outstanding, diluted	134,413	134,228

Basic net income per share was calculated using the weighted average number of shares outstanding for the period. The Company uses the treasury stock method to calculate net income per share. The calculation of diluted weighted average common shares excludes shares related to stock options and warrants that are anti-dilutive. For the year ended December 31, 2019, the Company's net income per share was $0.26 (2018 – $1.03) and did not differ from diluted earnings per share.

14. Capital Management

The Company's capital includes its working capital, senior secured loans and share capital. At December 31, 2019, the Company had $82,133 of working capital, before the current portions of net unrealized hedging liabilities and deferred consideration.

During 2019, the Company completed an amendment of its senior secured first lien term loan which resulted in the maturity date of over 90% of the outstanding balance being extended by two years to July 31, 2022, and made principal repayments totaling US$29,167 or C$38,552, resulting in an outstanding balance of US$171,908 or $223,308 at year-end. In addition, included in working capital at December 31, 2019 is US$32,974 or $42,833 of principal to be repaid by July 31, 2020 related to the cash sweep for the fourth quarter of 2019 and the maturity of the non-extended portion of the term loan. At December 31, 2019, Osum was in full compliance with its asset-based financial covenants. Further, the Company has access to a US$15,000 revolving line of credit which matures on April 30, 2022 and is currently undrawn. Details of the Company’s debt and equity capital are discussed in notes 11 and 13, respectively.

As a means to manage its capital exposure, the Company has an active commodity hedging program that is executed over time on a rolling basis targeting 50% of forecast bitumen production, net of maximum royalties. See note 7 for further details.

15. Risk Management

Credit Risk

Credit risk is the risk that the counterparty to a financial asset will default, resulting in the Company incurring a financial loss. The Company evaluates credit risks on an ongoing basis, including a review of counterparty credit ratings. The Company also maintains counterparty credit limits and portfolio and position limits based on commitment length, credit strength and counterparty concentration. Osum's objective is to have no credit losses. The primary sources of credit risk for the Company arise from cash and cash equivalents, accounts receivable, risk management contracts and Goods and Services Tax (GST) credits. Credit risk for the Company is considered to be low. Cash and cash equivalents consist of cash currently held in Government of Alberta guaranteed business or special interest savings accounts. The Company's risk management assets and the vast majority of the Company's accounts receivable, which relate to blend sales revenue, are owed by a small number of large, well-established oil and gas entities and financial institutions. At December 31, 2019, the Company's estimated maximum exposure to credit risk related to customers was considered to be inconsequential. There were no significant amounts that were aged greater than 90 days as at December 31, 2019.

Liquidity Risk

Liquidity risk is the risk that the Company will not be able to meet obligations associated with financial liabilities as they become due, including interest and principal related to its long-term debt. The Company's financial liabilities also include accounts payable and accrued liabilities which are composed primarily of amounts due in respect of the development and operation of the Company's projects along with risk management contracts and certain other corporate expenses. Payment terms on these amounts are typical trade terms for the industry and generally do not bear interest. The Company frequently assesses its liquidity position and obligations by preparing regular short-term and long-term cash flow forecasts. Liquidity risk is mitigated by ensuring all investments are short term and a sufficient cash balance is maintained to meet expected future payments. The Company also has access to its US$15,000 revolving line of credit, which was undrawn at December 31, 2019. See further discussion on capital management in note 14.

Market Risk

Market risk is the risk that the fair value of future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risks include interest rate risk, foreign currency risk, and commodity price risk. The Company evaluates market risks on an ongoing basis, including consideration of possible hedging strategies, and assesses the impact of variability in identified market risks on short and medium-term cash requirements.

(i) Commodity price risk

Commodity price risk arises from the effect that fluctuations of future commodity prices may have on the fair value of future cash flows or financial assets or liabilities. Commodity prices have fluctuated widely during recent years due to global and regional factors including supply and demand fundamentals, inventory levels, transportation restrictions, government regulation and weather, economic, and geopolitical factors. Commodity prices have an effect on the amount of revenue earned by the Company on the sale of its bitumen production and impact the amount the Company pays for natural gas, electricity, and diluent, which are all costs incurred in the process of producing and transporting bitumen for sale.

To mitigate fluctuations in commodity prices the Company maintains an active commodity hedging program. The Company's hedging objective is to increase the certainty of Canadian-dollar operating cash flows as a source of funding by reducing commodity price volatility through the use of financially settled derivatives. Over time and on a rolling basis, the Company hedges WTI, the WTI-WCS differential and the WTI-condensate differential into Canadian dollars, targeting 50% of forecast bitumen production, net of maximum royalties. In addition, the Company hedges natural gas targeting 50% of expected purchases.

(ii) Foreign currency risk

Foreign currency risk is the risk that a variation in exchange rates between the Canadian dollar and foreign currencies will affect the fair value or future cash flows of the Company's financial assets or liabilities. The Company has US dollar denominated long-term debt as described in note 11 and therefore makes interest and principal payments in US dollars. As at December 31, 2019, a C$0.10 change in the exchange rate of US$1 = C$1.2990 (increase – US$1 = C$1.3990, decrease – US$1 = 1.1990) would have resulted in a corresponding change in the carrying value of long-term debt of $17,191 (December 31, 2018 – $20,108).

The Company’s revenues are based on the US dollar, since revenue received from the sale of bitumen and bitumen blend is generally referenced to a price denominated in US dollars. The Company incurs most of its operating and other costs in Canadian dollars. As a result, the Company is impacted by exchange rate fluctuations between the US dollar and the Canadian dollar, and any strengthening of the Canadian dollar relative to the US dollar could negatively impact the Company’s operating margins and cash flows. To mitigate this risk, the Company's commodity hedges noted above are denominated in Canadian dollars.

(iii) Interest rate risk

The Company is exposed to interest rate cash flow risk on its floating rate long-term debt. During the year ended December 31, 2019, a 100 basis point increase in LIBOR would have decreased the Company's net income before taxes by $2,600 (2018 – $2,674) while a 100 basis point decrease in LIBOR would have increased the Company's net income before taxes by $2,600 (2018 – $2,477).

(Expressed in thousands of Canadian dollars)

16. Petroleum Sales and Product Purchases

The Company produces bitumen from its Orion facility near Cold Lake, Alberta. The bitumen is blended with purchased diluent and marketed as a heavy crude oil blend known as Cold Lake Blend. Other than the recognition of deferred consideration described in note 17 and sales of purchased diluent in excess of the Company's blending requirements, the sale of blended bitumen is the Company’s only source of revenue from contracts with customers. The Company sells its blended bitumen pursuant to short-term physical delivery contracts with several non-governmental counterparties. Monthly per barrel transaction prices for variable-price contracts are based on commodity settlement prices, adjusted for quality, location and other factors or fees.

The Company considers the delivery of each barrel of blended bitumen to be a distinct performance obligation as each barrel has the same use and value to the counterparty and that value is not related to or dependent upon the other contracted barrels. The amount of revenue recognized is based on the agreed transaction price per barrel of blended bitumen and the volumes delivered. The Company has no long-term contracts with unfulfilled performance obligations.

In addition to sales of blended bitumen, petroleum sales include revenue from sales of purchased diluent in excess of the Company's blending requirements. The associated purchases of those excess volumes are included in product purchases on the consolidated statement of income. Also included in product purchases are purchases of blended bitumen necessary to meet contractual commitments. The table below summarizes petroleum sales and product purchases. Comparative figures have been reclassified to conform with the current period presentation:

For the years ended December 31,	2019	2018
Blended bitumen sales	547,257	241,956
Diluent sales	15,193	4,298
Petroleum sales	562,450	246,254
Blended bitumen purchases	16,922	646
Diluent purchases	15,193	4,298
Product purchases	32,115	4,944

Arrangements for the transportation of blended bitumen are made separately and are not performance obligations of contracts with customers. Transportation expenses are recorded within "Diluent and transportation" on the statements of net and comprehensive income.

Separate from its blended bitumen sales contracts but often, though not exclusively, with the same counterparties, the Company also has contracts to purchase diluent for use in blending. Blended bitumen sales and diluent purchases with the same counterparty are typically settled monthly on a net basis, but are recorded on a gross basis on the statements of net and comprehensive income. In those cases, all blended bitumen revenue, net of any diluent purchases, is collected from each counterparty on the business day nearest the 25th day of the month following the month of delivery. Given the size and financial stability of the counterparties and their history of reliable and timely payment, no allowance for doubtful receivables is maintained.

(Expressed in thousands of Canadian dollars)

17. Deferred Consideration

In 2017, the Company sold a 4.0% gross overriding royalty interest on all current and future production from the Clearwater formation of its Orion property for cash proceeds.

Deferred consideration represents the portion of proceeds attributable to the upfront payment received for costs expected to be incurred by the Company in relation to future production of the royalty owner's 4.0% share of proved and probable reserves.

A reconciliation of deferred consideration for the period is shown below:

For the years ended December 31,	2019	2018
Balance – beginning of year	64,048	64,047
Implied interest benefit	6,207	6,020
Revenue – deferred consideration	(2,787)	(5,991)
Transaction costs	—	(28)
Balance – end of year	67,468	64,048
Less: current portion of deferred consideration	(1,420)	(1,156)
Deferred consideration	66,048	62,892

The Company's deferred consideration is considered a contract liability that implicitly contains a financing component as the payment was received in advance of the Company's incurrence of any costs related to production of the royalty owner's share of proved and probable reserves. The imputed interest expense resulting from the financing component was recorded and the implied interest benefit was added to the deferred consideration. The imputed interest was calculated using 9.5%, which reflected the Company's estimated cost of borrowing at contract inception.

During the year ended December 31, 2019, the Company recognized $2,787 (2018 – $5,991) of revenue related to the deferred consideration.

18. Lease Liabilities

	Year ended December 31, 2019
Balance – beginning of year (recorded on adoption of IFRS 16)	1,306
Liabilities incurred	290
Interest expense – lease liabilities (note 19)	100
Lease payments	(620)
Liabilities derecognized	(55)
Balance – end of year	1,021
Less: current portion of lease liabilities	(499)
Long term portion of lease liabilities	522

The Company has lease liabilities for contracts related to office space, equipment rentals, information technology and vehicle rentals. Lease terms are negotiated on an individual basis and contain a wide range of terms and conditions. Discount rates ranging from 9.5% to 11.6% were used during the year ended December 31, 2019.

(Expressed in thousands of Canadian dollars)

Where the Company has the right to extend a lease term at its discretion and is reasonably certain to exercise the extension option, the extension option is included in the calculation of finance lease liability.

Undiscounted cash outflows relating to the lease liabilities, including principal and interest, are:

	As at December 31, 2019
Year 1	620
Year 2	487
Year 3	198
Total	1,305

19. Net Finance Costs

For the years ended December 31,	2019	2018
Interest expense and fees – long-term debt	27,850	20,804
Amortization and derecognition of deferred transaction costs (note 11)	3,523	1,955
Interest income	(1,639)	(2,728)
Interest expense – deferred consideration (note 17)	6,207	6,020
Interest expense – lease liabilities (note 18)	100	—
Realized foreign exchange loss	535	141
Net finance costs	36,576	26,192

20. Contractual Obligations and Commitments

The information presented in the table below reflects management's estimate of the contractual maturities of the Company's obligations for its oil sands properties and its general corporate activities as at December 31, 2019.

	Total	2020	2021	2022	2023+
Contracts and purchase orders (1)	3,218	3,030	155	33	—
Transportation agreements (2)	70,310	16,576	13,076	10,621	30,037
Outstanding share units (3)	8,526	2,560	3,103	2,863	—
Interest and fees on term loan (4)	45,363	18,335	17,191	9,837	—
Repayment of term loan (4)	223,308	42,833	—	180,475	—
Total	350,725	83,334	33,525	203,829	30,037

(1) Minimum commitments or buyouts relating to contracts and purchase orders, including those related to the Orion expansion projects, costs for the storage of the evaporators procured for use at Taiga, future operating costs for the head office lease and information technology contracts.
(2) Firm service gas and bitumen blend transportation commitments.
(3) Cash taxes related to share units expected to be settled in shares and unaccrued fair value of outstanding share units expected to be settled in cash.
(4) Minimum obligations under the term loans using the foreign exchange and interest rates in effect as at December 31, 2019.

(Expressed in thousands of Canadian dollars)

21. Supplemental Cash Flow Information

For the years ended December 31,	2019	2018
Changes in non-cash operating working capital		
Accounts receivable	(13,817)	11,759
Prepaid expenses and other assets	(179)	53
Accounts payable and accrued liabilities	4,705	(7,298)
	(9,291)	4,514
Changes in non-cash investing working capital		
Accounts receivable	590	(592)
Accounts payable and accrued liabilities	446	(14,487)
	1,036	(15,079)

Supplemental cash flow information		
Cash interest earned	1,411	2,689
Cash interest paid	27,950	20,804

The following table presents the cash and non-cash changes in financing liabilities arising from financing activities:

	Term Loan		Lease Liabilities	
	2019	2018	2019	2018
Balance – beginning of year	270,917	250,127	1,306	—
Cash changes:				
Principal repayments	(38,552)	(2,760)	(520)	—
Debt issue costs	(1,940)	—	—	—
Non-cash changes:				
Unrealized foreign exchange gain	(12,427)	21,595	—	—
Amortization and derecognition of debt issue costs	3,523	1,955	—	—
Lease liabilities incurred	—	—	290	—
Lease liabilities derecognized	—	—	(55)	—
Balance – end of year	221,521	270,917	1,021	—

(Expressed in thousands of Canadian dollars)

22. Wages and Employee Benefits Costs

For the years ended December 31,	2019	2018
Capitalized:		
Salaries, short-term benefits and other	2,432	3,077
Share-based compensation	954	821
Expensed:		
Salaries, short-term benefits and other	20,852	20,272
Share based compensation expense	10,963	6,344

23. Compensation of Key Management Personnel

Key management personnel are composed of the Company's directors and executive officers. Their compensation is as follows:

For the years ended December 31,	2019	2018
Salaries, short-term benefits and other	2,909	3,007
Share based compensation expense	4,012	3,683

24. Subsequent Event

Subsequent to December 31, 2019, significant declines in crude oil spot prices and in stock markets have occurred for various reasons linked to the COVID-19 pandemic and other conditions impacting worldwide oil prices. The Company's impairment tests for oil sands properties are based on fair value less costs of disposal. As required by IFRS, the Company has not reflected these subsequent conditions in the recoverable amount estimates of its oil sands assets at December 31, 2019.

Impairment indicators for the Company's oil sands properties could exist at March 31, 2020, if current conditions persist. Management continues to work on revisions to forecasts and development plans in light of the current conditions and will use these updated assumptions and forecasts in its impairment indicator analysis and for impairment tests as at March 31, 2020, if such tests are required.

Corporate Information

Directors

William A. Friley – Chairman
Independent Businessman

Roy Ben-Dor
Managing Director, Warburg Pincus LLC

Vincent Chahley
Independent Businessman

George Crookshank
Independent Businessman

Jeffrey Kelly
Managing Director, Blackstone Capital Partners and Blackstone Energy Partners

John Lee
Principal, Blackstone Capital Partners and Blackstone Energy Partners

Francesco Mele
Chief Operating Officer, Azimuth Capital Management

Brian Reinsborough
Founder and Chief Executive Officer, Novara Energy LLC

Steve Spence
President and Chief Executive Officer, Osum Oil Sands Corp.

Officers

Steve Spence, P.Eng.
President and CEO

Victor Roskey
Chief Financial Officer

Rick K. Walsh, P.Eng.
Chief Operating Officer

Dr. Peter Putnam, P.Geol.
Sr. Vice President, Geoscience

Dr. Jen Russel-Houston, P.Geol
Vice President, Geoscience

Auditor
PricewaterhouseCoopers LLP
Calgary, Alberta

Independent Engineers
GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Legal Counsel
McCarthy Tetrault LLP
Calgary, Alberta

Registrar and Transfer Agent
Alliance Trust Company
Calgary, Alberta

Financial Institution
ATB Financial
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2019 Annual Report

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