STRATHCONA RESOURCES LTD

2024 Annual Report

About Strathcona

Headquartered in Calgary, Alberta, Strathcona is one of North America's fastest-growing oil and gas companies and Canada's fifth largest liquids producer.

Engaged in the acquisition, exploration, development and production of petroleum and natural gas reserves across Western Canada, Strathcona principally operates in three core areas: Cold Lake, Lloydminster and Montney. Strathcona's products are sold in Canada or transported to sales points in the United States via rail or pipeline. Strathcona's common shares are listed on the Toronto Stock Exchange under the symbol SCR.

Contents

2024 Highlights

39 years

2P reserve life index
Positioned for significant future growth

$1.3B

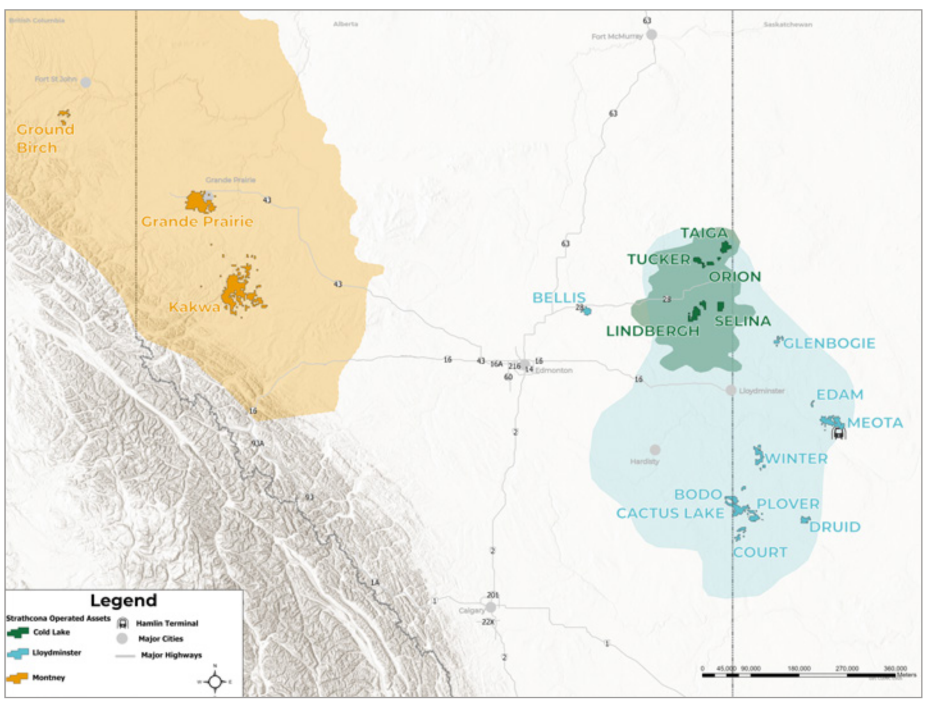
Capital spending on growth
While generating top-tier returns and excess free cash flow

183,080 boe/d

Average daily production in 2024
Delivering safe, reliable and responsible performance

0.69

Total recordable injury frequency
Everyone is responsible to uphold the highest safety standards



Message to Shareholders

2024 marked Strathcona's eighth year of operation and our first full year as a public company. It was also our first year without a major acquisition. In the absence of a large deal, 2024 was an opportunity for us to focus inward and ensure we are properly set up to organically maximize the value of our asset base. 2024 was light on headlines, but much like in the oil business, the real action happened "below the surface" which we expect will bear fruit in coming years.

Starting with safety, our performance in 2024 was strong relative to industry benchmarks, but slightly below our standout metrics in 2023. Our Total Recordable Injury Frequency per 200,000 manhours of 0.69 was above our 2023 performance of 0.49, but still below industry averages. Importantly, at Strathcona we record *every* slip, trip or nick sustained on the job, by both employees and contractors. Of the 35 recordable injuries over the course of 10.1 million manhours, 33 were classified as low severity, with the individual returning to work the same day. We are big believers in "what gets measured gets done" which means every incident is reviewed with Strathcona's board of directors quarterly, regardless of severity.

Turning to our financials, 2024 operating earnings[2] of $971 million were up 22% year-over-year, or approximately 14% on a per share basis. This reflected production growth to 183 Mboe per day (71% oil and condensate, 78% liquids)[3], up 18% from 2023 (or 10% per share) and a 4% improvement in operating earnings per boe to $14.51. 2024 was also a record year for capital spending of approximately $1.3 billion, with all three of our reporting segments – Cold Lake, Lloydminster and Montney – attracting capital well above sustaining levels. Despite higher spending, capital efficiency remained strong, achieving a PDP[4] recycle ratio of 2.4x[2]. Finally, 2024 also saw Strathcona pay its first two quarterly dividends of $0.25/share, after achieving our debt target of $2.5 billion mid-year.

Operationally, performance varied across each business unit, reinforcing our strategy of maintaining a portfolio of properties versus a single asset. In particular, 2024 was an exceptional year for our Lloydminster Conventional business, with record production and PDP[4] reserves growth, driven by a combination of doing what our team has always done well – managing base declines across hundreds of mature wells, especially at our polymer floods in Cactus Lake and Bodo-Cosine – as well as new development approaches such as our first multilateral and infill wells at Druid. Cold Lake also had a good year, with lower base production declines than expected and strong reserves growth in all categories. Performance in our Lloydminster Thermal and Montney business units were mixed, with higher production downtime being a challenge. We have total confidence in the new leadership in place at both business units, and early returns from 2025 indicate that this year could be our best yet for each.

Zooming out from current year activity, 2024 also included two major strategic announcements from Strathcona. In July, we announced a first of its kind partnership with Canada Growth Fund, with the goal of developing up to $2 billion in carbon capture and storage infrastructure on Strathcona's asset base that is expected to capture up to two million tonnes of CO_2 per year. The partnership is uniquely structured to minimize Strathcona's upfront capital exposure, effectively providing the company a low-cost hedge against its future carbon taxes. In November, Strathcona held its first Investor Day, where we outlined our first detailed long-range development plan which targets production growth of more than 50% to 290 Mboe per day by 2030. It is an ambitious plan which will require outstanding execution from our teams in the coming years, but we are confident we can pull it off.

Finally, 2024 was perhaps most important in terms of what we did on the people front. In the fourth quarter of 2024 we reorganized into four semi-autonomous business units, (Cold Lake, Lloydminster Thermal, Lloydminster Conventional and Montney), each with their own president directly accountable for their day-to-day operations. While much has been extolled about the economies of scale which come with getting bigger (and many of these are real, particularly cost of capital,

Message to Shareholders (continued)

procurement and overhead), much less discussed are the equally real diseconomies of scale. In particular, the importance of being lean and focused, two absolute requirements of a start-up, generally recede into the background as companies get bigger and stronger. Strathcona has now drilled over 600 wells, and it is natural that our next 10 feel less important than our first 10. That kind of complacency can become pernicious to performance over time, and we are determined to make sure that doesn't happen at Strathcona. With this re-organization, we aim to get the best of both worlds: the low overhead, access to capital, and stability of a large enterprise, combined with the meritocracy and accountability of a start-up.

We remain optimistic that Strathcona's best years are far in front of it and we remain committed to updating our shareholders about each triumph and setback we experience in coming years (and there will undoubtedly be a mix of both). We treat our role as stewards of your capital seriously and appreciate the confidence you have placed in us.

Adam Waterous
Executive Chairman
of the Board of Directors

1 Certain statements contained in this letter constitute forward-looking information within the meaning of applicable securities laws. The forward-looking information in this letter is based on Strathcona's current internal expectations, estimates, projections, assumptions and beliefs. Such forward-looking information is not a guarantee of future performance and involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. Refer to the "Forward Looking Information" section in the MD&A.
2 A non-GAAP financial measure or ratio which does not have a standardized meaning under IFRS® Accounting Standards (the "Accounting Standards"); see "Non-GAAP Financial Measures and Ratios" section in our management's discussion and analysis for the year ended December 31, 2024 (the "MD&A") included herein.
3 Refer to the "Advisories Regarding Oil & Gas Information" section in the MD&A included herein.
4 Proved Developed Producing.

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following management's discussion and analysis ("**MD&A**") of financial condition and results of operations for Strathcona Resources Ltd. (the "**Company**" or "**Strathcona**") is dated March 4, 2025 and should be read in conjunction with the Company's audited consolidated financial statements (and related notes) as at and for the years ended December 31, 2024 and 2023 (the "**annual financial statements**"). The annual financial statements have been prepared in accordance with IFRS® Accounting Standards (the "**Accounting Standards**") as issued by the International Accounting Standards Board, in Canadian dollars, except where indicated otherwise. The annual financial statements and MD&A of Strathcona have been prepared by management, reviewed by the Audit Committee of the Company's Board of Directors and were approved by the Company's Board of Directors.

This MD&A contains forward looking information; see "Risk Factors" and "Forward-Looking Information" in this MD&A for further information. The following MD&A also contains financial measures that do not have a standardized meaning under the Accounting Standards; see "Specified Financial Measures" at the end of this MD&A for further information. This MD&A contains certain oil and gas metrics and measures; see "Advisories Regarding Oil & Gas Information" at the end of this MD&A.

All dollar amounts are referenced in Canadian dollars and, in the case of amounts presented in tabular form, in millions of Canadian dollars, in each case except when noted otherwise. All per unit figures are based on commodity sales volumes, net of blending. Sales volumes differ from production volumes as a result of changes in oil inventory. Refer to the "Segment Results" section of this MD&A for additional information.

DESCRIPTION OF BUSINESS

Strathcona is a corporation resulting from the amalgamation of Strathcona Resources Ltd. and Pipestone Energy Corp. ("**Pipestone**") on October 3, 2023 (the "**Pipestone Acquisition**"), as part of a plan of arrangement under the Business Corporations Act (Alberta) (the "**ABCA**"), (the "**Arrangement**"). Upon completion of the Arrangement, Strathcona's common shares ("**Common Shares**") were listed on the TSX under the trading symbol "SCR" and commenced trading on October 5, 2023. Strathcona exists under, and is governed by, the provisions of the ABCA.

The significant differences in financial and operational results of the Company for the year ended December 31, 2024 compared to the year ended December 31, 2023 within this MD&A are primarily the result of the Pipestone Acquisition. Refer to Note 4 of the annual financial statements for further details.

RECENT DEVELOPMENTS

On January 31, 2025, certain limited partnerships comprising Waterous Energy Fund and its affiliates (collectively, "**WEF**") completed a share pass-through transaction that resulted in a disposition of 24,010,576 Common Shares, representing approximately 11.2% of the issued and outstanding Common Shares. Following completion of this transaction, the ownership of the Common Shares held by WEF collectively decreased from approximately 90.8% to approximately 79.6%.

Effective March 4, 2025, US President Donald Trump confirmed Canadian energy products imported to the United States will be subject to a 10 per cent tariff. Of the approximately 115 Mbbls per day of bitumen and heavy oil Strathcona produces, approximately 85 Mbbls per day ("**Local Sales**") is sold in Western Canada markets and approximately 30 Mbbls per day is sold in the United States Gulf Coast ("**USGC Sales**"). Tariffs are expected to impact Strathcona's Local Sales to the extent they cause a widening in WTI-WCS Hardisty differentials, and in the fourth quarter of 2024 Strathcona hedged 45 Mbbls per day (approximately 53% of Local Sales) at a US$12.94 / bbl differential for full-year 2025. In the first quarter of 2025, Strathcona hedged approximately 21 Mbbls per day (approximately 70% of USGC sales) at a WTI-WCS Houston differential of US$3.52 per barrel between April and September 2025. It is not known how long tariffs will be in place, but Strathcona expects that their financial impact has been mitigated through much of 2025 because of these risk management contracts.

GUIDANCE

Strathcona's 2024 and 2025 annual guidance and actual results are outlined below:

	2024 Guidance(1)	2024 Actual	2025 Guidance
Production (Mboe/d)	**183**	**183**	**185 – 195**
Capital expenditures ($ millions)	**1,300**	**1,296**	**1,350**

(1) As announced on November 13, 2024 and disclosed in the Company's MD&A for the three and nine months ended September 30, 2024 and 2023.

PRODUCTION VOLUMES

	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Bitumen (bbl/d)	**59,732**	59,845	58,610	**59,516**	55,768
Heavy oil (bbl/d)	**50,997**	52,736	50,494	**51,107**	53,707
Condensate and light oil (bbl/d)	**20,763**	19,184	19,520	**19,922**	12,011
Total oil production (bbl/d)	**131,492**	131,765	128,624	**130,545**	121,486
Other NGLs (bbl/d)	**12,980**	11,906	11,680	**11,958**	9,021
Natural gas (mcf/d)	**256,386**	254,361	227,581	**243,456**	149,715
Total (boe/d)	**187,203**	186,064	178,235	**183,080**	155,459
% oil and condensate	**70 %**	71 %	72 %	**71 %**	78 %
% liquids	**77 %**	77 %	79 %	**78 %**	84 %

Production volumes increased 1% (or 1,139 boe per day) for the three months ended December 31, 2024 to an average of 187,203 boe per day compared to 186,064 boe per day for the same quarter of 2023. The increase is primarily attributable to new wells brought on stream in the Montney segment.

Production volumes increased 18% (or 27,621 boe per day) for the year ended December 31, 2024 to an average of 183,080 boe per day compared to 155,459 boe per day for the same period of 2023. The increase is primarily attributable to production from properties at Grande Prairie that were added through the Pipestone Acquisition completed in the fourth quarter of 2023 which contributed 30,545 boe per day in the year ended December 31, 2024 (December 31, 2023 - 7,651 boe per day). The remaining production increase is attributable to new wells drilled as part of the Company's capital program.

Production volumes increased 5% (or 8,968 boe per day) during the three months ended December 31, 2024 to an average of 187,203 boe per day compared to 178,235 boe per day for the three months ended September 30, 2024. This increase is primarily related to the Montney segment where production increased as a result of more favorable operating and gas pricing environments and from new well production in Kakwa. Production in the Montney segment for the three months ended September 30, 2024 was negatively impacted by planned and unplanned outages at third-party processing plants at Grande Prairie and deliberate production curtailments in Groundbirch in response to low gas prices. Production was restored at Groundbirch in the fourth quarter and third party processing facilities in Grande Prairie experienced better run times.

SALES VOLUMES

	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Bitumen (bbl/d)	**59,796**	60,027	58,422	**59,491**	55,766
Heavy oil (bbl/d)	**47,850**	50,849	50,839	**50,848**	54,169
Condensate and light oil (bbl/d)	**20,763**	19,184	19,520	**19,922**	12,011
Total oil production (bbl/d)	**128,409**	130,060	128,781	**130,261**	121,946
Other NGLs (bbl/d)	**12,980**	11,906	11,680	**11,958**	9,021
Natural gas (mcf/d)	**256,386**	254,361	227,581	**243,456**	149,715
Total (boe/d)	**184,120**	184,360	178,391	**182,794**	155,920

Sales volumes typically trend with production volumes, except in cases of an inventory build or draw. Strathcona carries inventory on rail cars in transit to the US Gulf Coast, on pipelines and in storage tanks. In the fourth quarter of 2024, the Company had a build up of heavy oil inventory related to volumes transported by rail due to weather conditions, which resulted in congestion at major rail hubs. Heavy oil inventory was sold shortly after year-end.

BUSINESS ENVIRONMENT

	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Benchmark Pricing					
US$/bbl unless otherwise indicated					
WTI[1]	**70.27**	78.32	75.10	**75.72**	77.62
WCS Hardisty[2]	**57.72**	56.43	61.55	**60.97**	58.92
WCS USGC[3]	**65.69**	71.59	68.51	**69.69**	69.73
WTI-WCS Hardisty differential	**(12.55)**	(21.89)	(13.55)	**(14.75)**	(18.70)
WTI-WCS USGC differential	**(4.58)**	(6.73)	(6.59)	**(6.03)**	(7.89)
NYMEX-AECO differential (US$/MMbtu)[4]	**(1.86)**	(1.13)	(1.62)	**(1.33)**	(0.79)
Condensate differential[5]	**0.39**	(2.09)	(3.90)	**(2.78)**	(1.03)
Average Exchange rate (C$/US$)	**1.3992**	1.3618	1.3636	**1.3700**	1.3495
CAD$/bbl unless otherwise indicated					
WTI[1]	**98.30**	106.72	102.43	**103.70**	104.78
WCS Hardisty[2]	**80.75**	76.85	83.96	**83.53**	79.51
WCS USGC[3]	**91.90**	97.49	93.45	**95.46**	94.10
AECO 5A (C$/gj)[6]	**1.40**	2.18	0.65	**1.38**	2.50
Condensate par at Edmonton	**98.85**	103.81	97.10	**99.92**	103.36
AESO weighted average pool price (C$/MWh)[7]	**53.10**	83.05	58.75	**64.54**	136.45
CORRA (%)[8]	**3.83**	5.03	4.54	**4.59**	4.75

(1) Calendar month average of West Texas Intermediate (“WTI”) oil.
(2) Western Canadian Select (“WCS”).
(3) United States Gulf Coast (“USGC”).
(4) New York Mercantile Exchange (“NYMEX”) Futures Last Day differential / Relates to the Alberta Energy Company (“AECO”) 7A Index.
(5) Condensate / WTI differential at Edmonton.
(6) AECO hub pricing.
(7) Alberta Electric System Operator (“AESO”) weighted average pool prices.
(8) Canadian Overnight Repo Rate Average (“CORRA”).

WTI crude oil prices decreased 6% in the fourth quarter of 2024 compared to the third quarter of 2024 due to concerns about excess global crude supply, as the global market transitioned to a surplus in the fourth quarter of 2024. OPEC+ extended their 2.2 MMbpd production cut until April 2025 and announced plans to phase in their production increases more gradually than initially planned due to the supply surplus. The decrease in the WTI crude oil price due to excess supply was partially offset by speculation about policy changes under a new Trump administration.

The WTI-WCS Hardisty differential narrowed relative to WTI by 7% in the fourth quarter of 2024 compared to the third quarter of 2024. The continued strength in the differential was attributed to Western Canadian inventories remaining near the bottom of the five-year range, bolstered by surplus egress capacity as the Trans Mountain Pipeline Expansion came online in May 2024.

The WTI-WCS USGC differential narrowed relative to WTI by 31% in the fourth quarter of 2024 compared to the third quarter of 2024 due to low inventories in the USGC. Lower inventories were attributed to reduced imports of Mexican crude to the USGC due to production challenges and disruptions to the US Gulf of Mexico production from storms.

AECO 5A natural gas prices increased 113% in the fourth quarter of 2024 compared to the third quarter of 2024 due to colder than average weather in November and December resulting in storage draws. However, Canadian storage still remains significantly above the five-year average as production remains close to record high levels.

REVENUE AND REALIZED PRICES

Oil and Natural Gas Sales – Net of Blending

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2024**	 December 31, 2023	 September 30, 2024	Year Ended **December 31, 2024**	 December 31, 2023
Bitumen blend	**632.2**	591.8	616.8	**2,576.0**	2,280.8
Heavy oil, blended and raw	**409.9**	437.3	441.8	**1,795.7**	1,809.1
Condensate and light oil	**180.3**	172.3	169.9	**704.7**	431.0
Other natural gas liquids	**27.2**	26.9	24.0	**106.1**	79.4
Natural gas	**43.2**	59.3	20.0	**153.9**	148.0
Oil and natural gas sales	**1,292.8**	1,287.6	1,272.5	**5,336.4**	4,748.3
Gain (loss) purchased product	**(0.5)**	1.0	0.5	**—**	(0.2)
Bitumen – blending cost	**(232.6)**	(243.5)	(200.6)	**(929.9)**	(890.3)
Heavy oil – blending cost	**(35.1)**	(41.3)	(31.2)	**(151.6)**	(168.0)
Oil and natural gas sales, net of blending[1]	**1,024.6**	1,003.8	1,041.2	**4,254.9**	3,689.8

(1) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see "Specified Financial Measures" section of this MD&A.

Oil and natural gas sales, net of blending, increased 2% (or $20.8 million) for the three months ended December 31, 2024 to $1,024.6 million compared to $1,003.8 million in the same quarter of 2023. This increase was primarily attributable to higher average realized oil prices, partially offset by lower average realized natural gas prices.

Oil and natural gas sales, net of blending, increased 15% (or $565.1 million) for the year ended December 31, 2024 to $4,254.9 million compared to $3,689.8 million for the same period in 2023. This increase was primarily attributable to increased sales volumes at Grande Prairie from properties acquired in the Pipestone Acquisition which was completed in the fourth quarter of 2023, higher average realized oil prices, partially offset by lower average realized natural gas prices.

Oil and natural gas sales, net of blending, decreased 2% (or $16.6 million) for the three months ended December 31, 2024 to $1,024.6 million compared to $1,041.2 million from the third quarter of 2024. This decrease is primarily due to lower average realized oil prices, partially offset by increased sales volumes and higher average realized natural gas prices.

Average Realized Prices

	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Bitumen blend ($/bbl)[(1)(2)]	**72.62**	63.07	77.47	**75.61**	68.31
Heavy oil, blended and raw ($/bbl)[(1)(2)]	**85.05**	84.23	87.88	**88.34**	83.00
Condensate and light oil ($/bbl)	**94.39**	97.62	94.61	**96.64**	98.30
Realized oil ($/bbl)	**80.81**	76.46	84.13	**83.79**	77.79
Other natural gas liquids ($/bbl)	**22.78**	24.56	22.33	**24.24**	24.12
Natural gas ($/mcf)	**1.83**	2.53	0.96	**1.73**	2.71
Combined ($/boe)	**60.49**	59.17	63.44	**63.60**	64.83

(1) Realized prices are calculated using oil and natural gas sales and sales of purchased product, net of blending and purchased product.

(2) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see “Specified Financial Measures” section of this MD&A.

Combined realized price increased 2% (or $1.32 per boe) for the three months ended December 31, 2024 to $60.49 per boe compared to $59.17 per boe in the same quarter of 2023. The increase was primarily attributable to the strengthening of the WCS Hardisty benchmark as a result of narrowed differentials and reduced blending costs due to lower condensate benchmark pricing.

Combined realized price decreased 2% (or $1.23 per boe) for the year ended December 31, 2024 to $63.60 per boe compared to $64.83 per boe in the same period of 2023. The decrease was primarily attributable to lower natural gas price benchmarks which had a greater impact in the year ended December 31, 2024 as the Company's sales mix was more heavily weighted to natural gas due to the acquisition of Pipestone, partially offset by increased WCS Hardisty and USGC benchmark pricing.

Combined realized price decreased 5% (or $2.95 per boe) for the three months ended December 31, 2024 to $60.49 per boe compared to $63.44 per boe for the three months ended September 30, 2024. The decrease was due to a decrease in the WCS Hardisty and USGC benchmark prices combined with higher per barrel blend costs as colder weather necessitated more diluent in order to meet pipeline specifications.

ROYALTIES

($ millions, unless otherwise indicated)	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Crown royalties[(1)]	**188.2**	96.3	97.5	**528.3**	405.1
Freehold royalties[(1)]	**6.8**	14.0	7.5	**30.4**	56.7
Gross overriding royalties[(1)]	**10.5**	17.2	22.2	**81.5**	73.9
Other royalties	**3.0**	7.4	6.8	**22.5**	21.2
Royalties	**208.5**	134.9	134.0	**662.7**	556.9
Effective royalty rate (%)[(1)]	**20.3 %**	13.4 %	12.9 %	**15.6 %**	15.1 %

(1) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see “Specified Financial Measures” section of this MD&A.

For the three months ended and year ended December 31, 2024, the effective royalty rate was 20.3% and 15.6%, respectively, compared to 13.4% and 15.1% for the same periods in 2023. For the three months ended December 31, 2024, the effective royalty rate increased compared to 12.9% in the third quarter of 2024. These increases are primarily attributable to the timing of eligibility of capital deductions relating to projects at thermal properties.

PRODUCTION AND OPERATING EXPENSES

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Production and operating – Energy(1)	**58.7**	72.5	45.7	**248.1**	322.3
Production and operating – Non-energy(1)	**138.5**	133.3	140.2	**563.6**	474.0
Production and operating expenses	**197.2**	205.8	185.9	**811.7**	796.3
Production and operating – Energy ($/boe)(1)	**3.46**	4.27	2.78	**3.71**	5.66
Production and operating – Non-energy ($/boe)(1)	**8.18**	7.86	8.54	**8.42**	8.33
Production and operating expenses ($/boe)	**11.64**	12.13	11.32	**12.13**	13.99

(1) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see “Specified Financial Measures” section of this MD&A.

Production and operating expenses decreased 4% (or $8.6 million) for the three months ended December 31, 2024 to $197.2 million ($11.64 per boe) from $205.8 million ($12.13 per boe) in the same period of 2023. Energy costs decreased by $13.8 million ($0.81 per boe) primarily due to lower natural gas and power benchmark prices. Non-energy costs increased by $5.2 million ($0.32 per boe) primarily due to increased chemical costs as a result of sulphur recovery units installed at the Company’s Cold Lake segment in the first quarter of 2024.

Production and operating expenses increased 2% (or $15.4 million) for the year ended December 31, 2024 to $811.7 million ($12.13 per boe), from $796.3 million ($13.99 per boe) in the same period of 2023. Energy costs decreased by $74.2 million ($1.95 per boe) primarily due to lower natural gas and power benchmark prices and savings realized on carbon taxes as a result of carbon credit purchases, partially offset by increased carbon taxes as certain thermal properties in Saskatchewan entered their first year of compliance. Non-energy costs increased by $89.6 million ($0.09 per boe) primarily due to $62.7 million in incremental costs relating to properties acquired in the Pipestone Acquisition and increased chemical costs at Cold Lake as a result of sulphur recovery units installed in the first quarter of 2024.

Energy production and operating costs increased 28% (or $13.0 million) for the three months ended December 31, 2024 to $58.7 million ($3.46 per boe), compared to $45.7 million ($2.78 per boe) for the three months ended September 30, 2024. The increase is primarily due to higher natural gas prices and carbon taxes impacting the Cold Lake segment in the fourth quarter of 2024. Non-energy production and operating costs decreased to $138.5 million ($8.18 per boe) for the three months ended December 31, 2024 compared to $140.2 million ($8.54 per boe) for the three months ended September 30, 2024. The decrease was primarily due to a decrease in labour related costs as well as surface maintenance costs.

TRANSPORTATION AND PROCESSING EXPENSES

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2024**	 December 31, 2023	 September 30, 2024	Year Ended **December 31, 2024**	 December 31, 2023
Transportation expenses[1]	**117.8**	109.7	116.1	**471.9**	435.9
Processing expenses[1]	**26.4**	26.0	24.1	**105.1**	47.0
Transportation and processing expenses	**144.2**	135.7	140.2	**577.0**	482.9
$ per boe	**8.51**	8.00	8.54	**8.62**	8.49

(1) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see "Specified Financial Measures" section of this MD&A.

Transportation and processing expenses increased 6% (or $8.5 million) for the three months ended December 31, 2024 to $144.2 million (8.51 per boe) compared to $135.7 million ($8.00 per boe) in the same period of 2023. The increase is primarily attributable to increased bitumen transportation costs, as well as the Company benefiting from certain cost savings due to the utilization of make-up rights at Cold Lake in the comparable period.

Transportation and processing expenses increased 19% (or $94.1 million) for the year ended December 31, 2024 to $577.0 million ($8.62 per boe) compared to $482.9 million ($8.49 per boe) in the same period of 2023. These increases are primarily the result of increased sales volumes from the properties acquired in the Pipestone Acquisition, increased bitumen transportation costs due to cost savings in 2023 that resulted from the utilization of make-up rights, partially offset by decreased heavy oil transportation due to lower volumes sold on rail. The incremental transportation and processing costs associated with the properties acquired in the Pipestone Acquisition for the three months and year ended December 31, 2024 were $30.7 million and $125.0 million, respectively.

Transportation and processing expenses increased 3% (or $4.0 million) for the three months ended December 31, 2024 to $144.2 million ($8.51 per boe) from $140.2 million ($8.54 per boe) in the three months ended September 30, 2024. The increase was primarily attributable to higher natural gas transportation and processing charges resulting from increased production in the Montney segment, partially offset by reduced rail transportation costs as lower volumes were transported by rail in the fourth quarter of 2024.

DEPLETION, DEPRECIATION AND AMORTIZATION ("DD&A")

($ millions, unless otherwise indicated)	Three Months Ended **December 31, 2024**	 December 31, 2023	 September 30, 2024	Year Ended **December 31, 2024**	 December 31, 2023
Depletion expense[1]	**181.9**	214.8	212.5	**819.3**	699.6
Depreciation and amortization expense[1]	**14.4**	12.7	13.8	**54.2**	33.3
DD&A	**196.3**	227.5	226.3	**873.5**	732.9
$ per boe	**11.59**	13.41	13.79	**13.06**	12.88

(1) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see "Specified Financial Measures" section of this MD&A.

DD&A expense decreased 14% (or $31.2 million) for the three months ended December 31, 2024 to $196.3 million ($11.59 per boe) compared to $227.5 million ($13.41 per boe) for the same period of 2023. This decrease was primarily attributable to updated depletion rate estimates in the Montney segment.

DD&A expense increased 19% (or $140.6 million) for the year ended December 31, 2024 to $873.5 million ($13.06 per boe), compared to $732.9 million ($12.88 per boe) for the same period of 2023. This increase was primarily due to an increase in production volumes as a result of the Pipestone Acquisition.

DD&A expense decreased 13.3% (or $30.0 million) during the three months ended December 31, 2024 to $196.3 million ($11.59 per boe) compared to $226.3 million ($13.79 per boe) for the three months ended September 30, 2024. This decrease was primarily attributable to updated depletion rate estimates in the Montney segment.

GENERAL AND ADMINISTRATION EXPENSES ("G&A")

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
G&A expenses	**28.4**	24.5	25.5	**101.1**	91.9
$ per boe	**1.68**	1.44	1.55	**1.51**	1.61

For the three months and year ended December 31, 2024, G&A expenses increased 16% (or $3.9 million) and 10% (or $9.2 million) to $28.4 million ($1.68 per boe) and $101.1 million ($1.51 per boe), respectively, compared to $24.5 million ($1.44 per boe) and $91.9 million ($1.61 per boe) for the same periods in 2023. These increases were primarily the result of increased personnel and information technology costs.

G&A expenses increased 11% (or $2.9 million) during the three months ended December 31, 2024, $28.4 million ($1.68 per boe) compared to $25.5 million ($1.55 per boe) for the three months ended September 30, 2024. The increase was primarily due to increased personnel costs.

INTEREST

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Interest expense	**39.0**	51.6	42.1	**170.2**	206.2
Weighted average interest rate (%)	**5.8 %**	6.7 %	6.1 %	**6.1 %**	6.5 %

For the three months and year ended December 31, 2024, interest expense decreased 24% (or $12.6 million) and 17% (or $36.0 million) to $39.0 million and $170.2 million, respectively, compared to $51.6 million and $206.2 million in the same periods of 2023. Interest expense decreased 7% (or $3.1 million) for the three months ended December 31, 2024 to $39.0 million compared to $42.1 million for the three months ended September 30, 2024. These decreases were primarily the result of lower debt levels and lower interest rates.

During the year ended December 31, 2024, the Company recorded $47.1 million in interest expense on the Senior Notes (as defined in the "Capital Resources" section of this MD&A) (December 31, 2023 – $46.4 million), and $146.1 million in interest expense on the Credit Facilities (as defined in the "Capital Resources" section of this MD&A) (December 31, 2023 - $178.4 million), and a realized gain of $23.0 million on interest rate swaps (December 31, 2023 - $18.6 million).

The impact of changes in interest rates is partially mitigated through interest rate swaps, see the "Risk Management - Market Risk - Interest Rate Risk" section of this MD&A.

FINANCE COSTS

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Accretion of lease obligations	**5.9**	5.9	5.9	**24.1**	14.5
Accretion of decommissioning provision	**7.1**	7.1	7.1	**28.3**	28.7
Amortization of debt issuance costs	**5.1**	3.5	6.3	**20.5**	13.0
Accretion of other obligations	**2.9**	5.1	2.6	**15.4**	19.1
Finance costs	**21.0**	21.6	21.9	**88.3**	75.3

Finance costs for the three months ended December 31, 2024 remained consistent at $21.0 million compared to $21.6 million for the same period of 2023.

Finance costs increased 17% (or $13.0 million) to $88.3 million for the year ended December 31, 2024 compared to $75.3 million in the same period of 2023. This increase was primarily due to higher accretion of lease obligations as a result of contracts assumed in the Pipestone Acquisition and higher amortization of debt issuance costs as a result of fees incurred on the increase of the borrowing capacity under the Revolving Credit Facility (as defined in the "Capital Resources" section of this MD&A). On March 28, 2024 the Company increased the Revolving Credit Facility to $2.5 billion from $2.3 billion and extended the maturity date to March 28, 2028; provided that the maturity date will be May 1, 2026 if the Senior Notes (as defined in the “Capital Resources” section of this MD&A) remain outstanding and have not been refinanced or legally defeased at such date.

Finance costs remained consistent for the three months ended December 31, 2024 at $21.0 million compared to $21.9 million for the three months ended September 30, 2024.

TAX POOLS

As at December 31, 2024, the Company had approximately $5,595.4 million (December 31, 2023 - $6,081.1 million) of tax pools available for deduction in future periods as shown in the table below.

($ millions, unless otherwise indicated)	Annual Pool Deduction Rate	**December 31, 2024**	December 31, 2023
Canadian oil and gas property expenditures(1)	10%	**838.5**	893.4
Canadian development expenditures(1)	30%	**1,279.7**	1,168.8
Canadian exploration expenditures(1)	100%	**18.3**	34.1
Undepreciated capital costs(2)	4% - 55%	**1,502.6**	1,371.0
Non-capital losses	100%	**1,707.6**	2,173.1
Other(1)(3)		**248.7**	440.7
Total tax pools		**5,595.4**	6,081.1

(1) Amount is net of tax pools where deductibility is uncertain.

(2) As at December 31, 2024, approximately 92% (December 31, 2023 – 96%) of costs in this pool have an annual deduction rate of 25%.

(3) "Other" tax pools are comprised of federal and provincial scientific research and experimental development expenditure pools and credits and financing costs.

RISK MANAGEMENT

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities. These risks include credit risk, liquidity risk and market risk.

Credit Risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. This will arise principally from outstanding receivables related to oil and natural gas customers, counterparties with which financial derivative contracts are held, and joint interest partners.

On entering into any business contract, the extent to which the arrangement exposes the Company to credit risk is considered. The Company's policy to mitigate credit risk associated with these balances is to establish relationships with reputable counterparties, review the financial capacity of its counterparties, request prepayment as deemed advisable and, in certain circumstances, the Company may seek enhanced credit protection from a counterparty or purchase accounts receivable insurance.

Market Risk

Market risk is the risk that the future fair value or cash flows of a financial instrument will fluctuate due to changes in market prices. Market risk is composed of commodity price risk, foreign exchange risk and interest rate risk. The Company uses financial risk management contracts to reduce volatility in financial results and to ensure a certain level of cash flow to fund planned capital projects.

Commodity Price Risk

The Company's operational results and financial condition are largely dependent on the commodity price received for oil and natural gas production. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, weather, economic and geopolitical factors. The Company uses financial derivative instruments and other commodity derivative mechanisms to help limit the adverse effects of commodity price volatility. However, the Company does not have commodity contracts in place for all its production and expects there will always be a portion that remains unhedged. Furthermore, the Company may use financial derivative instruments that offer only limited protection within selected price ranges. To the extent price exposure is hedged, the Company may forego the benefits that would otherwise be experienced if commodity prices increase.

The following table summarizes the Company's commodity contracts outstanding as at the date of this MD&A.

Term	Contract[(1)]	Index	Currency	Volume	Units	Price
Jan 1, 2025 - Dec 31, 2025	Swap	WCS	USD	45,000	bbl/d	$(12.94)
Apr 1, 2025 - Jun 30, 2025	Swap	ARV	USD	18,500	bbl/d	$(3.59)
Jul 1, 2025 - Sep 30, 2025	Swap	ARV	USD	23,500	bbl/d	$(3.46)
Dec 1, 2024 - Mar 31, 2025	Collar	AECO	CAD	30,000	GJ/d	$2.50/$3.51

(1) For swap contracts, Strathcona receives the fixed price and pays the index. For collars, Strathcona receives the floor price if the index is below the floor and the cap price if the index is above the cap.

Foreign Exchange Risk

The Company is exposed to fluctuations of the CAD to USD exchange rate given commodity pricing is directly influenced by USD denominated benchmark pricing. In addition, the Company periodically borrows from its Credit Facilities in USD and the Senior Notes are denominated in USD. The Company actively manages foreign exchange risk using foreign exchange derivatives.

The following table summarizes the Company's foreign exchange contract on revenues as at the date of this MD&A.

Term	Contract	Bought Put - USD per Month	Bought Put Price - CAD/USD	Sold Call - USD per Month	Sold Call - CAD/ USD
Feb 1, 2025 - Jun 30, 2026	Collar	100.0 million	1.2500	130.0 million	1.4500

The following table summarizes the Company's foreign exchange contract on the Senior Notes as at the date of this MD&A.

Expiry	Contract	USD	CAD/USD Strike
Jul 31, 2026	Sold Put Option	500.0 million	1.3775

Interest Rate Risk

The Company is exposed to movements in floating interest rates on the Credit Facilities. The Company is not exposed to interest rate risk on the Senior Notes or other liabilities as they bear a fixed interest rate.

The following table summarizes the Company's risk management contracts in place to fix interest rates as at the date of this MD&A.

Notional (C$)	Term	Contract	Index	Contract Price
1,500.0 million	Oct 1, 2024 - Apr 30, 2030	Swap(1)	CORRA	2.9453%

(1) The swap contracts have a term to April 30, 2030. The counterparties have an option to terminate the swap effective May 1, 2028, which is exercisable on April 28, 2028.

For a listing of the Company's commodity contracts, foreign exchange and interest rate contracts outstanding as at December 31, 2024 refer to Note 14 in the annual financial statements.

Refer to the "Capital Resources" section of this MD&A for information on the Company's cross-currency interest rate swaps related to debt.

The following table summarizes the Company's gains and losses on risk management contracts.

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Loss (gain) on risk management contracts - realized(1)	**5.4**	(19.5)	94.7	**107.0**	42.4
(Gain) loss on risk management contracts - unrealized	**(15.6)**	(109.6)	(78.1)	**(63.0)**	(112.0)
Total loss (gain) on risk management contracts	**(10.2)**	(129.1)	16.6	**44.0**	(69.6)
Realized loss (gain) on risk management contracts per boe	**0.32**	(1.15)	5.77	**1.60**	(0.74)

(1) During the year ended December 31, 2024, the Company settled premiums associated with expired bought calls for non-cash consideration of $112.4 million (see "Other Obligations" section in this MD&A).

Strathcona realized a loss on risk management contracts of $5.4 million for the three months ended December 31, 2024, compared to a gain of $19.5 million for the same period in 2023. The realized loss in the three months ended December 31, 2024 was primarily due to cash settlement of the loss position on foreign exchange contracts resulting from the weakened Canadian dollar and losses on commodity contracts.

Strathcona realized a loss on risk management contracts of $107.0 million for the year ended December 31, 2024 compared to a loss of $42.4 million in the same period of 2023. The realized loss for the year end December 31, 2024 was primarily due to the settlement of premiums associated with expired bought calls for non-cash consideration of $112.4 million in the third quarter of 2024, partially offset by cash settlement of gain positions on WTI crude oil contracts.

As at December 31, 2024, the mark-to-market value of risk management contracts was a net liability of $40.7 million (December 31, 2023 - net liability of $103.7 million). Unrealized gains and losses represent the change in the mark-to-market values of these contracts due to the fluctuation of forward commodity prices, exchange rates and interest rates. The significant assumptions made in determining the fair value of financial instruments are disclosed in Note 14 to the annual financial statements.

CAPITAL EXPENDITURES

The following table summarizes the Company's capital expenditures by segment.

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Cold Lake	**138.3**	69.7	96.0	**371.7**	306.0
Lloydminster	**138.3**	96.2	113.3	**445.2**	360.5
Montney	**112.9**	139.3	108.4	**470.3**	351.0
Corporate	**3.0**	2.6	1.9	**9.0**	10.9
Capital expenditures	**392.5**	307.8	319.6	**1,296.2**	1,028.4

The following table summarizes the Company's capital expenditures by category.

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Drilling, completion and equipping	**170.6**	177.3	175.5	**674.6**	592.5
Facilities and pipelines	**172.5**	96.5	113.1	**456.0**	311.0
Recompletion, workovers and polymer powder	**34.3**	19.2	19.4	**106.9**	70.1
Capitalized G&A and other expenditures	**15.1**	14.8	11.6	**58.7**	54.8
Capital expenditures	**392.5**	307.8	319.6	**1,296.2**	1,028.4

For the three months ended December 31, 2024, drilling, completion and equipping activities accounted for 43% of capital expenditures as the Company drilled 81 new wells during the fourth quarter of 2024; 22 in Cold Lake, 49 in Lloydminster and 10 in Montney. For the year ended December 31, 2024, drilling, completion and equipping activities accounted for 52% of capital expenditures as the Company drilled 268 new wells during the year; 60 at Cold Lake, 177 in Lloydminster and 31 in Montney. For the year ended December 31, 2024 facilities and pipeline expenditures accounted for 35% of capital expenditures and relate primarily to Lindbergh debottlenecking, Meota West 2 OTSG addition, Meota Central brownfield development and the Kakwa 6-8 facility expansion.

For the three months and year ended December 31, 2024, capital expenditures increased 28% (or $84.7 million) and 26% (or $267.8 million) to $392.5 million and $1,296.2 million, respectively, compared to $307.8 million and $1,028.4 million for the same periods of 2023. Capital expenditures increased 23% (or $72.9 million) for the three months ended December 31, 2024 to $392.5 million compared to $319.6 million for the three months ended September 30, 2024. Capital expenditures will vary year over year depending on annual capital expenditure guidance. Full year 2024 capital expenditures were in line with annual guidance of $1.3 billion.

FOREIGN EXCHANGE

	Three Months Ended			Year Ended	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Realized (gain) loss	**(3.6)**	(0.1)	2.6	**0.5**	(1.4)
Unrealized loss (gain) - Senior Notes	**42.9**	(16.8)	(7.7)	**57.0**	(15.6)
Unrealized loss (gain) - Credit Facilities	**39.3**	(38.0)	1.0	**69.8**	(47.2)
Unrealized (gain) loss - cross-currency swaps	**(38.7)**	36.7	(0.9)	**(68.2)**	43.9
Unrealized loss (gain) - other	**7.8**	(2.7)	(1.8)	**9.1**	(1.8)
Foreign exchange loss (Gain)	**47.7**	(20.9)	(6.8)	**68.2**	(22.1)

Foreign exchange for the three months ended December 31, 2024 resulted in a loss of $47.7 million compared to a gain of $20.9 million and a gain of $6.8 million for the three months ended December 31, 2023 and September 30, 2024, respectively. For the year ended December 31, 2024, foreign exchange resulted in a loss of $68.2 million compared to a gain of $22.1 million in the prior year. The foreign exchange gains and losses are driven by the CAD/USD exchange rate applied to U.S. dollar denominated debt balances net of cross-currency swaps.

SEGMENT RESULTS

The Company has identified three operating segments through examination of the Company's performance which is based on the similarity of services and goods provided and economic characteristics exhibited by the operating segments. The three operating segments are:

- Cold Lake, which includes the development and production of bitumen in the Cold Lake region of Northern Alberta;

- Lloydminster, which includes the development and production of heavy oil through enhanced oil recovery and thermal steam-assisted gravity drainage ("**SAGD**") methods in Southeast Alberta and Southwest Saskatchewan; and

- Montney, which includes the development and production of liquids rich natural gas produced from the Montney region in Northwest Alberta and Northeast British Columbia.

The Company reports activities not directly attributable to an operating segment under Corporate.

The following tables present the financial performance by reportable segment and include a measure of segment profit or loss regularly reviewed by management for the noted periods ended December 31, 2024 and 2023. Certain comparative information related to sale of purchased product and purchased product has been allocated by segment to conform with current period presentation. Field operating earnings is the metric used to evaluate segment profit or loss which includes depletion, depreciation and amortization. Field operating income, which excludes depletion, depreciation and amortization, was used to evaluate segment profit or loss in the comparative period.

For the Three Months Ended ($ millions, unless otherwise indicated)	Cold Lake Segment			Lloydminster Segment			Montney Segment			Corporate			Consolidated		
	Dec 31, 2024	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024
Production volumes															
Bitumen (bbl/d)	**59,732**	59,845	58,610	**—**	—	—	**—**	—	—	**—**	—	—	**59,732**	59,845	58,610
Heavy oil (bbl/d)	**—**	—	—	**50,997**	52,736	50,494	**—**	—	—	**—**	—	—	**50,997**	52,736	50,494
Condensate and light oil (bbl/d)	**—**	—	—	**64**	40	32	**20,699**	19,144	19,488	**—**	—	—	**20,763**	19,184	19,520
Other NGLs (bbl/d)	**—**	—	—	**4**	1	—	**12,976**	11,905	11,680	**—**	—	—	**12,980**	11,906	11,680
Natural gas (mcf/d)	**—**	—	—	**1,295**	1,260	1,150	**255,091**	253,101	226,431	**—**	—	—	**256,386**	254,361	227,581
Production volumes (boe/d)	**59,732**	59,845	58,610	**51,281**	52,987	50,718	**76,190**	73,232	68,907	**—**	—	—	**187,203**	186,064	178,235
Sales volumes (boe/d)	**59,796**	60,027	58,422	**48,134**	51,100	51,062	**76,190**	73,232	68,907	**—**		—	**184,120**	184,360	178,391
Segment revenues															
Oil and natural gas sales	**632.1**	592.0	616.9	**409.9**	437.8	442.3	**250.4**	257.8	213.4	**0.4**	—	(0.1)	**1,292.8**	1,287.6	1,272.5
Sales of purchased products	**—**	8.1	11.5	**5.6**	3.2	20.4	**—**	—	—	**10.0**	—	12.5	**15.6**	11.3	44.4
Blending costs	**(232.6)**	(243.5)	(200.6)	**(35.1)**	(41.3)	(31.2)	**—**	—	—	**—**	—	—	**(267.7)**	(284.8)	(231.8)
Purchased product	**—**	(7.3)	(11.4)	**(5.7)**	(3.0)	(20.1)	**—**	—	—	**(10.4)**	—	(12.4)	**(16.1)**	(10.3)	(43.9)
Oil and natural gas sales, net of blending(1)	**399.5**	349.3	416.4	**374.7**	396.7	411.4	**250.4**	257.8	213.4	**—**	—	—	**1,024.6**	1,003.8	1,041.2
Segment expenses															
Royalties	**132.9**	73.8	74.4	**52.1**	41.7	39.5	**23.5**	19.4	20.1	**—**	—	—	**208.5**	134.9	134.0
Production and operating – Energy(1)	**29.9**	39.6	19.4	**26.7**	31.4	24.7	**2.1**	1.5	1.6	**—**	—	—	**58.7**	72.5	45.7
Production and operating – Non-energy(1)	**49.5**	44.9	46.8	**44.9**	50.6	54.5	**44.1**	37.8	38.9	**—**	—	—	**138.5**	133.3	140.2
Transportation and processing	**22.3**	18.7	21.7	**66.3**	65.4	68.5	**55.6**	51.6	50.0	**—**	—	—	**144.2**	135.7	140.2
Field Operating Income(1)	**164.9**	172.3	254.1	**184.7**	207.6	224.2	**125.1**	147.5	102.8	**—**	—	—	**474.7**	527.4	581.1
Depletion, depreciation and amortization	**39.7**	42.9	42.2	**97.3**	103.5	103.7	**54.6**	76.7	76.0	**4.7**	4.4	4.4	**196.3**	227.5	226.3
Field Operating Earnings(1)	**125.2**	129.4	211.9	**87.4**	104.1	120.5	**70.5**	70.8	26.8	**(4.7)**	(4.4)	(4.4)	**278.4**	299.9	354.8
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**28.4**	24.5	25.5	**28.4**	24.5	25.5
Other (income) loss	**—**	—	—	**—**	—	—	**—**	—	—	**—**	0.1	(0.1)	**—**	0.1	(0.1)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**39.0**	51.6	42.1	**39.0**	51.6	42.1
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**21.0**	21.6	21.9	**21.0**	21.6	21.9
Operating Earnings(1)													**190.0**	202.1	265.4
Loss (gain) on risk management contracts - realized	**—**	—	—	**—**	—	—	**—**	—	—	**5.4**	(19.5)	94.7	**5.4**	(19.5)	94.7
(Gain) loss on risk management contracts - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**(15.6)**	(109.6)	(78.1)	**(15.6)**	(109.6)	(78.1)
Foreign exchange (gain) loss - realized	**—**	—	—	**—**	—	—	**—**	—	—	**(3.6)**	(0.1)	2.6	**(3.6)**	(0.1)	2.6
Foreign exchange loss (gain) - unrealized	**—**	—	—	**—**	—	—	**—**	—	—	**51.3**	(20.8)	(9.4)	**51.3**	(20.8)	(9.4)
Transaction related costs	**—**	—	—	**—**	—	—	**—**	—	—	**0.3**	(1.3)	0.3	**0.3**	(1.3)	0.3
Unrealized (gain) loss on Sable remediation fund	**—**	—	—	**—**	—	—	**—**	—	—	**—**	(0.3)	(0.2)	**—**	(0.3)	(0.2)
Loss on settlement of other obligations	**—**	—	—	**—**	—	—	**—**	—	—	**—**	—	4.4	**—**	—	4.4
Deferred tax expense	**—**	—	—	**—**	—	—	**—**	—	—	**64.3**	90.0	63.1	**64.3**	90.0	63.1
Income and comprehensive income													**87.9**	263.7	188.0

(1) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see “Specified Financial Measures” section of this MD&A.

For the Three Months Ended ($/boe)	Cold Lake Segment			Lloydminster Segment			Montney Segment			Corporate			Consolidated		
	Dec 31, 2024	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024	**Dec 31, 2024**	Dec 31, 2023	Sep 30, 2024
Segment revenues															
Oil and natural gas sales	**80.88**	76.00	83.80	**87.17**	86.86	89.40	**35.72**	38.26	33.66	**0.02**	—	(0.01)	**66.21**	65.82	68.24
Sales of purchased products	**—**	1.47	2.14	**1.26**	0.68	4.34	**—**	—	—	**0.59**	—	0.76	**0.92**	0.67	2.71
Blending costs	**(8.26)**	(12.90)	(6.35)	**(2.53)**	(2.52)	(1.88)	**—**	—	—	**—**	—	—	**(5.69)**	(6.71)	(4.84)
Purchased product	**—**	(1.32)	(2.12)	**(1.29)**	(0.64)	(4.28)	**—**	—	—	**(0.61)**	—	(0.76)	**(0.95)**	(0.61)	(2.67)
Oil and natural gas sales, net of blending[1]	**72.62**	63.25	77.47	**84.61**	84.38	87.58	**35.72**	38.26	33.66	**—**	—	(0.01)	**60.49**	59.17	63.44
Segment expenses															
Royalties	**24.16**	13.36	13.84	**11.77**	8.87	8.41	**3.35**	2.88	3.17	**—**	—	—	**12.31**	7.95	8.16
Production and operating – Energy[1]	**5.44**	7.17	3.61	**6.03**	6.68	5.26	**0.30**	0.22	0.25	**—**	—	—	**3.46**	4.27	2.78
Production and operating – Non-energy[1]	**9.00**	8.13	8.71	**10.14**	10.76	11.60	**6.29**	5.61	6.14	**—**	—	—	**8.18**	7.86	8.54
Transportation and processing	**4.05**	3.39	4.04	**14.97**	13.91	14.58	**7.93**	7.66	7.89	**—**	—	—	**8.51**	8.00	8.54
Field Operating Netback[1]	**29.97**	31.20	47.27	**41.70**	44.16	47.73	**17.85**	21.89	16.21	**—**	—	(0.01)	**28.03**	31.09	35.42
Depletion, depreciation and amortization	**7.22**	7.77	7.85	**21.97**	22.02	22.07	**7.79**	11.38	11.99	**0.28**	0.26	0.27	**11.59**	13.41	13.79
Field Operating Earnings Netback[1]	**22.75**	23.43	39.42	**19.73**	22.15	25.66	**10.06**	10.51	4.22	**(0.28)**	(0.26)	(0.28)	**16.44**	17.68	21.63
General and administrative	**—**	—	—	**—**	—	—	**—**	—	—	**1.68**	1.44	1.55	**1.68**	1.44	1.55
Other (income) expense	**—**	—	—	**—**	—	—	**—**	—	—	**—**	0.01	(0.01)	**—**	0.01	(0.01)
Interest expense	**—**	—	—	**—**	—	—	**—**	—	—	**2.30**	3.04	2.57	**2.30**	3.04	2.57
Finance costs	**—**	—	—	**—**	—	—	**—**	—	—	**1.24**	1.27	1.33	**1.24**	1.27	1.33
Operating Earnings[1]													**11.22**	11.92	16.19
Effective royalty rate (%)[1]	**33.3**	21.1	17.9	**13.9**	10.5	9.6	**9.4**	7.5	9.4				**20.3**	13.4	12.9

(1) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see “Specified Financial Measures” section of this MD&A.

For the Year Ended ($ millions, unless otherwise indicated)	Cold Lake Segment December 31, 2024	December 31, 2023	Lloydminster Segment December 31, 2024	December 31, 2023	Montney Segment December 31, 2024	December 31, 2023	Corporate December 31, 2024	December 31, 2023	Consolidated December 31, 2024	December 31, 2023
Production volumes										
Bitumen (bbl/d)	**59,516**	55,768	**—**	—	**—**	—	**—**	—	**59,516**	55,768
Heavy oil (bbl/d)	**—**	—	**51,107**	53,707	**—**	—	**—**	—	**51,107**	53,707
Condensate and light oil (bbl/d)	**—**	—	**42**	42	**19,880**	11,969	**—**	—	**19,922**	12,011
Other NGLs (bbl/d)	**—**	—	**2**	1	**11,956**	9,020	**—**	—	**11,958**	9,021
Natural gas (mcf/d)	**—**	—	**1,232**	1,080	**242,224**	148,635	**—**	—	**243,456**	149,715
Production volumes (boe/d)	**59,516**	55,768	**51,357**	53,930	**72,207**	45,761	**—**	—	**183,080**	155,459
Sales volumes (boe/d)	**59,491**	55,766	**51,097**	54,393	**72,206**	45,761	**—**	—	**182,794**	155,920
Segment revenues										
Oil and natural gas sales	**2,576.0**	2,279.2	**1,797.1**	1,812.5	**963.0**	655.5	**0.3**	1.1	**5,336.4**	4,748.3
Sales of purchased product	**18.3**	20.1	**26.0**	12.2	**—**	—	**30.7**	14.0	**75.0**	46.3
Blending costs	**(929.9)**	(888.1)	**(151.6)**	(170.2)	**—**	—	**—**	—	**(1,081.5)**	(1,058.3)
Purchased product	**(18.2)**	(19.5)	**(25.8)**	(11.9)	**—**	—	**(31.0)**	(15.1)	**(75.0)**	(46.5)
Oil and natural gas sales, net of blending[(1)]	**1,646.2**	1,391.7	**1,645.7**	1,642.6	**963.0**	655.5	**—**	—	**4,254.9**	3,689.8
Segment expenses										
Royalties	**385.3**	323.3	**181.7**	175.1	**95.7**	58.5	**—**	—	**662.7**	556.9
Production and operating – Energy[(1)]	**127.9**	198.4	**112.8**	120.5	**7.4**	3.4	**—**	—	**248.1**	322.3
Production and operating – Non-energy[(1)]	**196.0**	173.9	**203.7**	216.3	**163.9**	83.8	**—**	—	**563.6**	474.0
Transportation and processing	**87.7**	80.4	**276.2**	293.7	**213.1**	108.8	**—**	—	**577.0**	482.9
Field Operating Income[(1)]	**849.3**	615.7	**871.3**	837.0	**482.9**	401.0	**—**	—	**2,203.5**	1,853.7
Depletion, depreciation and amortization	**167.1**	148.9	**411.1**	423.2	**278.5**	145.9	**16.8**	14.9	**873.5**	732.9
Field Operating Earnings[(1)]	**682.2**	466.8	**460.2**	413.8	**204.4**	255.1	**(16.8)**	(14.9)	**1,330.0**	1,120.8
General and administrative	**—**	—	**—**	—	**—**	—	**101.1**	91.9	**101.1**	91.9
Other income	**—**	—	**—**	—	**—**	—	**(0.1)**	(1.0)	**(0.1)**	(1.0)
Interest expense	**—**	—	**—**	—	**—**	—	**170.2**	206.2	**170.2**	206.2
Finance costs	**—**	—	**—**	—	**—**	—	**88.3**	75.3	**88.3**	75.3
Current income tax (recovery)	**—**	—	**—**	—	**—**	—	**—**	(46.9)	**—**	(46.9)
Operating Earnings[(1)]									**970.5**	795.3
Loss (gain) on risk management contracts - realized	**—**	—	**—**	—	**—**	—	**107.0**	42.4	**107.0**	42.4
(Gain) loss on risk management contracts - unrealized	**—**	—	**—**	—	**—**	—	**(63.0)**	(112.0)	**(63.0)**	(112.0)
Foreign exchange loss (gain) - realized	**—**	—	**—**	—	**—**	—	**0.5**	(1.4)	**0.5**	(1.4)
Foreign exchange loss (gain) - unrealized	**—**	—	**—**	—	**—**	—	**67.7**	(20.7)	**67.7**	(20.7)
Transaction related costs	**—**	—	**—**	—	**—**	—	**1.0**	3.8	**1.0**	3.8
Unrealized (gain) loss on Sable remediation fund	**—**	—	**—**	—	**—**	—	**(0.1)**	(0.2)	**(0.1)**	(0.2)
Loss on settlement of other obligations	**—**	—	**—**	—	**—**	—	**4.4**	—	**4.4**	—
Deferred tax expense	**—**	—	**—**	—	**—**	—	**249.3**	296.2	**249.3**	296.2
Income and comprehensive income									**603.7**	587.2

(1) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see "Specified Financial Measures" section of this MD&A.

For the Year Ended ($/boe)	Cold Lake Segment **December 31, 2024**	December 31, 2023	Lloydminster Segment **December 31, 2024**	December 31, 2023	Montney Segment **December 31, 2024**	December 31, 2023	Corporate **December 31, 2024**	December 31, 2023	Consolidated **December 31, 2024**	December 31, 2023
Segment revenues										
Oil and natural gas sales	**83.42**	79.53	**90.35**	85.58	**36.44**	39.24	**—**	0.01	**69.13**	71.36
Sales of purchased products	**0.84**	0.99	**1.39**	0.61	**—**	—	**0.46**	0.26	**1.12**	0.81
Blending costs	**(7.82)**	(11.19)	**(2.36)**	(2.85)	**—**	—	**—**	—	**(5.53)**	(6.52)
Purchased product	**(0.84)**	(0.96)	**(1.38)**	(0.60)	**—**	—	**(0.46)**	(0.27)	**(1.12)**	(0.82)
Oil and natural gas sales, net of blending[(1)]	**75.60**	68.37	**88.00**	82.74	**36.44**	39.24	**—**	—	**63.60**	64.83
Segment expenses										
Royalties	**17.69**	15.88	**9.72**	8.82	**3.62**	3.50	**—**	—	**9.91**	9.78
Production and operating – Energy[(1)]	**5.87**	9.75	**6.03**	6.07	**0.28**	0.20	**—**	—	**3.71**	5.66
Production and operating – Non-energy[(1)]	**9.00**	8.54	**10.89**	10.90	**6.20**	5.02	**—**	—	**8.42**	8.33
Transportation and processing	**4.03**	3.95	**14.77**	14.79	**8.06**	6.51	**—**	—	**8.62**	8.49
Field Operating Netback[(1)]	**39.01**	30.25	**46.59**	42.16	**18.28**	24.01	**—**	—	**32.94**	32.57
Depletion, depreciation and amortization	**7.67**	7.32	**21.98**	21.32	**10.54**	8.74	**0.25**	0.26	**13.06**	12.88
Field Operating Earnings Netback[(1)]	**31.34**	22.93	**24.61**	20.84	**7.74**	15.27	**(0.25)**	(0.26)	**19.88**	19.69
General and administrative	**—**	—	**—**	—	**—**	—	**1.51**	1.61	**1.51**	1.61
Other income	**—**	—	**—**	—	**—**	—	**—**	(0.02)	**—**	(0.02)
Interest expense	**—**	—	**—**	—	**—**	—	**2.54**	3.62	**2.54**	3.62
Finance costs	**—**	—	**—**	—	**—**	—	**1.32**	1.32	**1.32**	1.32
Current income tax (recovery)	**—**	—	**—**	—	**—**	—	**—**	(0.82)	**—**	(0.82)
Operating Earnings[(1)]									**14.51**	13.98
Effective royalty rate (%)[(1)]	**23.4**	23.2	**11.0**	10.7	**9.9**	8.9			**15.6**	15.1

(1) A non-GAAP financial measure which does not have a standardized meaning under the Accounting Standards; see “Specified Financial Measures” section of this MD&A.

Cold Lake Segment

Production at the Cold Lake segment for the three months ended December 31, 2024 decreased modestly to 59,732 boe per day compared to 59,845 boe per day in the same period of 2023. For the year ended December 31, 2024, production increased to 59,516 boe per day, compared to 55,768 boe per day in the same period of 2023. This increase was primarily due to strong well performance at the Company's Lindbergh and Tucker properties.

Oil and natural gas sales, net of blending, increased to $399.5 million ($72.62 per boe) during the three months ended December 31, 2024 compared to $349.3 million ($63.25 per boe) for the same quarter of 2023 primarily due to higher WCS Hardisty benchmark pricing and lower per barrel blend costs during the fourth quarter of 2024. During the year ended December 31, 2024 oil and natural gas sales, net of blending, increased to $1,646.2 million ($75.60 per boe) compared to $1,391.7 million ($68.37 per boe) for the same quarter of 2023. This increase was primarily due to higher sales volumes, increased WCS Hardisty benchmark pricing and lower per barrel blend costs compared to the same period of 2023.

The effective royalty rate for the three months and year ended December 31, 2024 increased to 33.3% and 23.4%, respectively, from 21.1% and 23.2% in the same periods of 2023. These increases were primarily attributable to the timing of eligibility of capital deductions.

Energy related production and operating expenses for the three months and year ended December 31, 2024 decreased to $29.9 million ($5.44 per boe) and $127.9 million ($5.87 per boe), respectively, compared to $39.6 million ($7.17 per boe) and $198.4 million ($9.75 per boe) in the same periods of 2023. These decreases were primarily attributable to the lower price of natural gas and electricity, and savings realized on carbon taxes as a result of carbon credit purchases.

Non-energy related production and operating expenses for the three months and year ended December 31, 2024 increased to $49.5 million ($9.00 per boe) and $196.0 million ($9.00 per boe), respectively, compared to $44.9 million ($8.13 per boe) and $173.9 million ($8.54 per boe), for the same periods of 2023. These increases were primarily due to increased chemical cost as a result of sulphur recovery units installed in the first quarter of 2024, which were fully operational in the second quarter of 2024.

For the three months ended December 31, 2024, transportation and processing expenses increased to $22.3 million ($4.05 per boe) from $18.7 million ($3.39 per boe) in the same period of 2023. For the year ended December 31, 2024, transportation and processing expenses increased to $87.7 million ($4.03 per boe) from $80.4 million ($3.95 per boe), in the same period of 2023. These increases were primarily attributable to increased bitumen transportation costs due to cost savings realized in 2023 due to the utilization of make-up rights.

Lloydminster Segment

Production from the Lloydminster segment for the three months and year ended December 31, 2024, decreased to 51,281 boe per day and 51,357 boe per day, respectively, compared to 52,987 boe per day and 53,930 boe per day in the same periods of 2023. These decreases were primarily due to lower production volumes from Saskatchewan thermal properties.

Oil and natural gas sales, net of blending, decreased to $374.7 million ($84.61 per boe) during the three months ended December 31, 2024 compared to $396.7 million ($84.38 per boe) for the same period of 2023. This decrease was primarily due to lower sales volumes. Oil and natural gas sales, net of blending, increased to $1,645.7 million ($88.00 per boe) during the year ended December 31, 2024 compared to $1,642.6 million ($82.74 per boe) for the same period of 2023. This increase was primarily attributable to higher WCS Hardisty and USGC benchmark pricing, partially offset by lower sales volumes.

The effective royalty rate for the three months and year ended December 31, 2024 increased to 13.9% and 11.0%, respectively, compared to 10.5% and 10.7% in the same periods of 2023. These increases were primarily attributable to the timing of eligibility of capital deductions.

Energy related production and operating expenses for the three months and year ended December 31, 2024 decreased to $26.7 million ($6.03 per boe) and $112.8 million ($6.03 per boe), respectively, compared to $31.4 million ($6.68 per boe) and $120.5 million ($6.07 per boe) for the same periods in 2023. These decreases were primarily attributable to the lower price of natural gas reducing gas purchases and lower price for electricity, partially offset by an increase in carbon taxes as certain thermal properties in Saskatchewan entered their first year of compliance.

Non-energy related production and operating expenses for the three months ended December 31, 2024 decreased to $44.9 million ($10.14 per boe) compared to $50.6 million ($10.76 per boe) in the same period of 2023. Non-energy related production and operating expenses for the year ended December 31, 2024 decreased to $203.7 million ($10.89 per boe), compared to $216.3 million ($10.90 per boe) for the same period in 2023. These decreases were primarily due to lower surface and downhole maintenance expenses resulting from lower production volumes.

For the three months ended December 31, 2024, transportation and processing expenses increased modestly to $66.3 million ($14.97 per boe) compared to $65.4 million ($13.91 per boe) in the same period of 2023. This increase per boe was primarily attributable to higher rail transportation charges due to an unfavorable CAD/USD exchange rate. For the year ended December 31, 2024, transportation and processing expenses decreased to $276.2 million ($14.77 per boe) from $293.7 million ($14.79 per boe) in the same period of 2023. This decrease was primarily due to lower sales volumes, partially offset by higher rail transportation charges due to an unfavorable CAD/USD exchange rate.

Montney Segment

Production at the Company's Montney segment for the three months and year ended December 31, 2024 increased to 76,190 boe per day and 72,207 boe per day, respectively, compared to 73,232 boe per day and 45,761 boe per day in the same periods of 2023. For the three months ended December 31, 2024, the increase was primarily due to new wells brought on stream in the fourth quarter of 2024. For the year ended December 31, 2024, these increases were primarily due to production from the properties acquired through the Pipestone Acquisition, which contributed 30,545 boe per day (December 31, 2023 - 7,651 boe per day) for the year ended December 31, 2024.

Oil and natural gas sales for the three months ended December 31, 2024 decreased to $250.4 million ($35.72 per boe) compared to $257.8 million ($38.26 per boe). This decrease was primarily due to lower commodity benchmark prices, offset by increased sales volumes. Oil and natural gas sales for the year ended December 31, 2024 increased to $963.0 million ($36.44 per boe) compared to $655.5 million ($39.24 per boe) in the same period of 2023. This increase was primarily due to incremental volumes from the Pipestone Acquisition, which contributed oil and natural gas sales of $440.6 million in year ended December 31, 2024. These increases were partially offset by a decrease in AECO benchmark prices, impacting natural gas sales.

For the three months ended December 31, 2024, effective royalty rate increased to 9.4% compared to 7.5% in the same quarter of 2023. This increase was primarily due to an increased weighting to production from wells that no longer qualify for incentive rates. For the year ended December 31, 2024, effective royalty rate increased to 9.9% compared to 8.9% in the same period of 2023 primarily due to a more favourable gas cost allowance credit in the comparative period.

Non-energy related production and operating expenses for the three months ended December 31, 2024 increased to $44.1 million ($6.29 per boe) compared to $37.8 million ($5.61 per boe) for the same period of 2023. Non-energy related production and operating expenses for the year ended December 31, 2024 increased to $163.9 million ($6.20 per boe), compared to $83.8 million ($5.02 per boe) in the same period of 2023. This increase was primarily attributed to increased gas processing fees at Grande Prairie and increased trucking costs at Kakwa due to delayed completion of a water disposal well.

Transportation and processing expenses for the three months ended December 31, 2024 increased to $55.6 million ($7.93 per boe) compared to $51.6 million ($7.66 per boe) in the same period of 2023. This increase was primarily attributable to higher sales volumes. Transportation and processing expenses for the year ended December 31, 2024 increased to $213.1 million ($8.06 per boe), compared to $108.8 million ($6.51 per boe) in the same period of 2023. These increases were primarily due to increased volumes added through the Pipestone Acquisition, which carry a higher per unit cost than the Company's other Montney assets as the production is processed through third-party facilities.

CAPITAL RESOURCES

Bank Credit Facilities

Covenant-Based Revolving Credit Facility and Term Credit Facility

As at December 31, 2024, the Company had a covenant-based revolving credit facility of $2.5 billion (December 31, 2023 - $2.3 billion) with a syndicate of Canadian, U.S. and international financial institutions (the "**Revolving Credit Facility**"). In January 2025, the Company amended and restated the credit agreement governing the Revolving Credit Facility to, among other things, add a US$175.0 million covenant-based term facility (the "**Term Credit Facility**" and together with the Revolving Credit Facility, the "**Credit Facilities**") to its bank Credit Facilities (such credit agreement as so amended and restated, the "**Credit Agreement**") and to incorporate an accordion feature which permits the Company to increase the Credit Facilities available under the Credit Agreement by up to an additional $250.0 million, subject to the satisfaction of certain conditions.

The Credit Facilities have a maturity date of March 28, 2028, provided that the maturity date will be May 1, 2026 if the Senior Notes (as defined below) remain outstanding and have not been refinanced or legally defeased at such date. There are no mandatory payments on either the Revolving Credit Facility or the Term Credit Facility. Borrowings under the Revolving Credit Facility may be drawn and repaid from time to time by the Company in Canadian or U.S. dollars. The Term Credit Facility was made available by way of a single advance, which was fully funded on January 29, 2025. Borrowings under the Term Credit Facility are available in U.S. dollars only and amounts repaid by the Company may not be re-borrowed. The proceeds of the Term Credit Facility were used to repay borrowings under the Revolving Credit Facility. In addition, the Revolving Credit Facility is not a borrowing base facility and does not require annual or semi-annual reviews.

The Credit Facilities bear interest at the applicable prime lending rate, base rate, Canadian Overnight Repo Rate Average ("**CORRA**") or Secured Overnight Financing Rate ("**SOFR**") plus applicable margins. The applicable margin charged by the lenders is dependent on the Company's Senior Debt to Adjusted EBITDA ratio (as defined below) for the most recently completed quarter. The Credit Facilities are guaranteed by the Company's subsidiaries, and are secured by a security interest in substantially all of the existing and future assets of the Company and its subsidiaries, including by way of a floating charge debenture granted by the Company and each of its subsidiaries.

As at December 31, 2024, the Company had letters of credit outstanding under the Revolving Credit Facility of $1.6 million (December 31, 2023 - $10.6 million).

Foreign Exchange Risk Management on U.S. Denominated Bank Debt

Strathcona periodically borrows in U.S. dollars and concurrently enters into cross-currency interest rate swap contracts to take advantage of an interest rate arbitrage that results from the relationship between Canadian and U.S. dollar interest rates and forward foreign exchange curves.

Foreign currency risk associated with these borrowings is offset at the time of borrowing as cross-currency interest rate swap contracts fix the principal and interest payments due at maturity. Debt on the balance sheet includes the Canadian dollar equivalent of U.S. borrowings translated at the period end exchange rate, which does not include the offsetting impact of cross-currency interest rate swaps. As at December 31, 2024 the cross-currency swap asset was $28.6 million (December 31, 2023 – a liability of $39.6 million) and total debt includes an unrealized loss of $28.6 million (December 31, 2023 – unrealized gain of $41.3 million) related to U.S. borrowings on the Revolving Credit Facility. Unrealized gains or losses on U.S. borrowings and offsetting unrealized gains or losses on cross-currency interest swap contracts are included in foreign exchange gains or losses in the annual financial statements.

As at December 31, 2024, the Company had the following cross-currency interest rate swap contracts outstanding totaling.

Notional (US$)	Maturity Date	Contract Price
1,235.0 million	January 17, 2025	CAD/USD 1.4153

Financial Covenants

The Credit Agreement has three financial covenants which are calculated quarterly (as set out below).

(i) Total Debt to Adjusted EBITDA Ratio – All debt excluding the Financing Agreement (see Note 7 of the annual financial statements), capital leases and letters of credit constituting debt ("**Total Debt**"), each as defined in the Credit Agreement shall not exceed 4.0 times trailing 12-month net income before non-cash items, income taxes, interest expense and extraordinary and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period (“**Adjusted EBITDA**”). For the purposes of Adjusted EBITDA, lease payments are deducted from the calculation if a lease would have been considered an operating lease before the adoption of IFRS 16. Total Debt may include the value of the Company’s undiscounted inactive abandonment and reclamation obligations for a material jurisdiction if the liability management ratio in that jurisdiction falls below the minimum maintenance level required under the Credit Agreement (1.0 in British Columbia and 2.0 in all other material jurisdictions). Liability management ratios are calculated by provincial regulators based on deemed asset and deemed liability values determined by the respective regulator, other than for British Columbia, which is calculated by the Company based on past practice of the BC Oil and Gas Commission.

(ii) Senior Debt to Adjusted EBITDA Ratio – Total Debt excluding permitted junior debt (e.g. Senior Notes), as defined in the Credit Agreement, shall not exceed 3.5 times trailing 12-month Adjusted EBITDA.

(iii) Interest Coverage Ratio – Trailing 12-month Adjusted EBITDA, shall not be less than 3.5 times cash interest expense ("**Interest Charges**"), as defined in the Credit Agreement.

As at December 31, 2024, the Company was in compliance with such financial covenants, which are summarized in the following table:

As at	December 31, 2024
Total Debt to Adjusted EBITDA Ratio (≤ 4.00)(1)	**1.20**
Senior Debt to Adjusted EBITDA Ratio (≤ 3.50)(1)	**0.85**
Interest Coverage Ratio (≥ 3.50)(1)	**10.95**

(1) See "Specified Financial Measures" section of this MD&A.

Senior Notes

As at December 31, 2024, Strathcona had $719.2 million (December 31, 2023 - $662.2 million) of senior unsecured notes outstanding, with an aggregate principal amount of US$500.0 million, due August 1, 2026 (the “**Senior Notes**”). The Senior Notes bear interest at 6.875% per annum, payable semi-annually in arrears on February 1 and August 1 of each year. The Senior Notes are redeemable at Strathcona’s option, in whole or in part, at the following redemption prices.

Date	Price
August 1, 2024	**101.719 %**
August 1, 2025 and thereafter	**100.000 %**

The Senior Notes have no financial maintenance covenants.

Demand Letter of Credit Facility

As at December 31, 2024, the Company had a $100.0 million (December 31, 2023 - $100.0 million) demand letter of credit facility with a financial institution (the “**LC Facility**”). The LC Facility is supported by an account performance security guarantee issued by Export Development Canada in favour of the financial institution. The Company and its subsidiaries have indemnified Export Development Canada for the amount of any payment made by Export Development Canada to the financial institution pursuant to such account performance security guarantee; however, the obligations under such indemnity are unsecured. The letters of credit outstanding under the LC Facility do not impact the Company’s borrowing capacity under the Revolving Credit Facility. As at December 31, 2024, the Company had letters of credit in the amount of $70.3 million (December 31, 2023 - $69.0 million) outstanding under the LC Facility.

CAPITAL MANAGEMENT AND LIQUIDITY

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility, creditor and market confidence and to sustain the future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Company considers its capital structure to include equity, long-term debt and working capital.

The Company generally relies on Funds from Operations and its Credit Facilities to fund its capital requirements, including its working capital deficiency. Future liquidity depends primarily on Funds from Operations, availability on the Revolving Credit Facility and the ability to access debt and equity markets. All repayments of principal on the Credit Facilities are due at its maturity date.

The availability under the Revolving Credit Facility is summarized in the following table.

As at	**December 31, 2024**	December 31, 2023
Credit capacity[1]	**2,500.0**	2,300.0
Revolving Credit Facility debt at period end exchange rate	**(1,766.9)**	(2,036.3)
Unrealized loss (gain) on U.S. borrowings	**28.6**	(41.3)
Letters of credit outstanding	**(1.6)**	(10.6)
Availability	**760.1**	211.8

(1) In January 2025, the credit capacity under the Credit Facilities increased to approximately $2.75 billion with the addition of the US$175.0 million Term Credit Facility.

The Company carries a working capital deficiency as part of its current capital structure. As at December 31, 2024, the working capital deficiency was $545.6 million (December 31, 2023 - $415.3 million). Management believes its current capital resources and its ability to manage cash flow and working capital levels will allow the Company to remedy its working capital deficiency, meet its current and future obligations, to make scheduled interest payments, to fund planned capital expenditures and to fund the other needs of the business for at least the next 12 months. However, no assurance can be given that this will be the case or that future or additional sources of capital will not be necessary. The Company's cash flow and the development of projects are subject to certain risk factors discussed in the "Risk Factors" section of this MD&A and the Annual Information Form for the year ended December 31, 2024.

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The oil and natural gas industry is cyclical and commodity prices can be volatile, both of which are expected to impact the Company's future revenue and profitability. A sustained decline in commodity prices and increased inflation and interest rates could adversely affect our business, financial condition and results of operations, liquidity and ability to meet financial commitments when due or delay planned capital expenditures. The imposition of tariffs or other tariff barriers will negatively impact the Company's realized prices, the timing of cash flows where production is directly exported by the Company and may increase certain of the Company's input costs.

The Company regularly prepares and updates budgets and forecasts in order to monitor its liquidity and ability to meet its financial obligations and commitments, including the ability to comply with the financial covenants under the Credit Facilities.

OTHER OBLIGATIONS

On August 9, 2024 Strathcona entered into a new asset-backed financing agreement backed by its interest in certain processing facility interests (the "**Financing Agreement**") for $112.4 million, which consideration was provided by way of the lender's concurrent assumption of premiums on bought calls from Strathcona.

The Financing Agreement has a maturity date of July 31, 2029 and bears interest at a fixed rate. Principal and interest payments are due monthly, with principal payments commencing February 1, 2025. The Company may also repurchase the processing facilities interest (the "**Repurchase Option**") at any time at the specified prices set out in the Financing Agreement. The Repurchase Option is a combination of the remaining principal balance and a varying option premium that is dependent on the time of exercise.

DECOMMISSIONING LIABILITY

At December 31, 2024, Strathcona's discounted decommissioning provision balance was $290.7 million (December 31, 2023 - $351.3 million) for future abandonment and reclamation of the Company's oil and natural gas properties. The reduction is primarily attributable to the change in the Company's credit adjusted risk-free rate from 8% in 2023 to 10% in 2024. During the year ended December 31, 2024, the Company incurred $35.7 million of decommissioning expenditures to settle existing liabilities. This amount was offset by additions made as a result of new wells and facilities, accretion and changes in estimates.

CONTRACTUAL OBLIGATIONS AND OFF-BALANCE SHEET ARRANGEMENTS

Strathcona has contractual obligations in the normal course of business which may include purchase of assets and services, operating agreements, transportation commitments, sales commitments, royalty obligations, lease rental obligations, employee agreements and debt. These obligations are of a recurring, consistent nature and impact Strathcona's cash flows in an ongoing manner.

The following tables detail the undiscounted cash flows and contractual maturities of the Company's financial liabilities as at December 31, 2024.

	Total	<1 year	1-3 years	4-5 years	> 5 years
Revolving Credit Facility(1)	**1,738.3**	—	1,738.3	—	—
Senior Notes(2)	**818.0**	49.4	768.6	—	—
Accounts payable and accrued liabilities	**918.7**	918.7	—	—	—
Risk management contract liability	**87.7**	44.6	43.1	—	—
Lease and other obligations(3)	**473.7**	91.4	151.6	143.8	86.9
Total	**4,036.4**	1,104.1	2,701.6	143.8	86.9

(1) Contractual amount reflects contracted settlement price on cross-currency interest rate swap ("**CCS**") contracts and excludes future interest payments on borrowings.

(2) Amounts represent repayment of the Senior Notes ($719.2 million) and associated interest payments ($98.8 million) based on the foreign exchange rate in effect on December 31, 2024.

(3) Amounts relate to undiscounted payments for lease and other obligations. The estimation of future cash payments related to other obligations reflects minimum required payments and may change based on the principal and interest payment options taken. See Note 7 of the annual financial statements.

As at December 31, 2024, the Company was committed to the following non-cancellable payments.

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Transportation and processing commitments	**2,052.7**	284.4	507.2	427.2	833.9
Capital commitments	**139.0**	136.0	3.0	—	—
Other	**27.2**	13.8	10.9	2.5	—
Total	**2,218.9**	434.2	521.1	429.7	833.9

In the normal course of business, the Company is obligated to make future payments, including contractual obligations and non-cancellable commitments. The Company generally expects to meet these commitments through funds from operations and draws on its Revolving Credit Facility. Strathcona does not maintain off-balance sheet transactions, arrangements, obligations or other relationships with unconsolidated entities or others that are reasonably likely to have a material current or future effect on the Company's financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources and which are not disclosed in the annual financial statements or notes thereto.

SHARE CAPITAL

The authorized capital of the Company consists of an unlimited number of Common Shares and an unlimited number of preferred shares. No preferred shares have been issued by the Company as at December 31, 2024 (December 31, 2023 – nil).

The following table summarizes the number of shares outstanding as at March 4, 2025:

Share Class	Shares Outstanding at March 4, 2025
Common Shares	214,235,608

The Company had no outstanding securities which are convertible into Common Shares or preferred shares as at March 4, 2025.

During the three months and year ended December 31, 2024, Strathcona declared and paid total dividends of $107.1 million, or $0.50 per Common Share ($nil - in the year ended December 31, 2023).

On March 4, 2025, the Board declared a quarterly dividend of $0.26 per Common Share to be paid on March 31, 2025 to all shareholders of record on March 21, 2025.

RISK FACTORS

The Company’s business is subject to numerous risks and uncertainties, any of which may adversely affect the Company’s business and its financial results and results of its operations. Certain of these risks and uncertainties are described at a high level within this MD&A. For additional information refer to the “Risk Factors” section in our Annual Information Form for the year ended December 31, 2024, a copy of which may be accessed through the SEDAR+ website (www.sedarplus.ca).

Risks Relating to Strathcona’s Business

Strathcona’s exploration and production activities are concentrated in BC, Alberta and Saskatchewan where activity is highly competitive and includes a variety of different-sized companies. Strathcona is subject to a number of risks that are common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, marketability of oil and gas produced, fluctuations in commodity prices, access to capital, financial and liquidity risks and environmental and safety risks.

Strathcona is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada and the United States. External factors beyond the Company’s control may affect the marketability of oil and gas produced. These factors include commodity prices and variations in the Canada-United States currency exchange rate which, in turn, responds to economic and political circumstances throughout the world. Oil prices are affected by worldwide supply and demand fundamentals while natural gas prices are affected by North American supply and demand fundamentals.

Exploration and production for oil and gas is capital intensive. Future capital expenditures may be financed in a variety of ways, including cash generated from operations, which fluctuates with changing commodity prices; borrowings, which exposes the Company to fluctuations in interest rates; and possible future equity offerings. Equity and debt capital are subject to market conditions, and availability and cost may increase or decrease from time to time.

Political and Social Events

Strathcona's results may be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and the duration of regulatory reviews could impact Strathcona's existing operations and planned projects. This includes actions by regulatory bodies or other political actors to delay or deny necessary licenses and permits for Strathcona's activities or restrict the operation of third-party infrastructure that Strathcona relies on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder (including Indigenous stakeholders) consultation requirements, may increase the cost of compliance or reduce or delay available business opportunities and have a material adverse effect on Strathcona's business, financial condition, results of operations and prospects.

Other government and political factors that could adversely affect Strathcona's financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements, including any changes to current tariff regimes and other non-tariff trade barriers. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or noncompetitive fuel components could adversely affect Strathcona's operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for Strathcona's products.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the crude oil and natural gas industry, including the balance between economic development and environmental policy. The crude oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding crude oil and natural gas development, particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt Strathcona's activities.

Climate Change Risks

Strathcona’s operations emit greenhouse gases (“**GHG**”) which may require us to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national, and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate its effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions both of which pose the risk of causing operational difficulties.

SELECTED ANNUAL INFORMATION

	Years Ended December 31,		
($ millions, unless otherwise indicated)	**2024**	2023	2022
Oil and natural gas sales	**5,336.4**	4,748.3	4,343.4
Net income	**603.7**	587.2	1358.2
Net income per share	**2.82**	2.94	0.63
Total assets	**10,977.5**	10,496.9	9,164.5
Total non-current liabilities	**4,027.7**	4,103.1	3,788.3
Dividends per share	**0.50**	—	—

SUMMARY OF QUARTERLY RESULTS

	2024				2023			
($ millions, unless otherwise indicated)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Operating results (boe/d)								
Average production volumes	**187,203**	178,235	181,766	185,122	186,064	147,461	143,778	144,160
Average sales volumes	**184,120**	178,391	185,841	182,862	184,360	148,874	143,239	146,877
Financial Results								
Oil and natural gas sales	**1,292.8**	1,272.5	1,472.3	1,298.8	1,287.6	1,300.2	1,112.8	1,047.7
Net Income (loss)	**87.9**	188.0	227.2	100.6	263.7	(41.1)	274.1	90.5
Net income (loss) per share	**0.41**	0.88	1.06	0.47	1.23	(0.02)	0.13	0.04
Cash flow from operating activities	**542.4**	521.9	519.7	408.8	570.0	430.5	343.1	181.1
Operating Earnings(1)	**190.0**	265.4	306.1	209.0	202.1	289.9	201.4	101.9
Funds from Operations(1)	**405.5**	528.7	547.6	455.6	470.8	425.3	389.2	276.9
Free Cash Flow(1)	**0.3**	200.6	247.3	157.9	150.8	158.0	152.6	36.1
Field Operating Income(1)	**474.7**	581.1	627.3	520.4	527.4	549.6	460.8	315.9
Field Operating Netback ($/boe)(1)	**28.03**	35.42	37.09	31.27	31.09	40.13	35.35	23.82
Field Operating Earnings(1)	**278.4**	354.8	398.2	298.6	299.9	378.0	290.1	152.8
Field Operating Earnings Netback ($/boe)(1)	**16.44**	21.63	23.54	17.94	17.68	27.60	22.25	11.48
Capital expenditures	**392.5**	319.6	298.0	286.1	307.8	260.2	231.7	228.7
Decommissioning expenditures	**12.7**	8.5	2.9	11.6	13.8	7.1	4.9	11.8
Total assets	**10,977.5**	10,663.3	10,670.9	10,597.8	10,496.9	9,588.9	9,451.2	9,289.5
Debt	**2,461.6**	2,449.9	2,435.6	2,642.5	2,665.0	2,787.6	2,898.2	3,041.7
Total equity	**5,823.7**	5,789.3	5,654.9	5,427.7	5,327.1	4,526.4	4,567.5	4,292.7
Common shares outstanding, end of period	**214.2**	214.2	214.2	214.2	214.2	2,186.7	2,186.7	2,186.5
Dividends per share	**0.25**	0.25	—	—	—	—	—	—

(1) A non-GAAP measure which does not have a standardized meaning under the Accounting Standards; see “Specified Financial Measures” section of this MD&A.

Over the past eight quarters, the Company’s oil and natural gas sales have fluctuated due to the Pipestone Acquisition (described in Note 4 of the annual financial statements), volatility in the crude oil, condensate and natural gas benchmark prices, oil price differentials and changes in production. The Company’s production has fluctuated due to asset acquisitions and dispositions, changes in its development capital spending levels and natural declines.

Net income (loss) has fluctuated over the past eight quarters primarily due to the Pipestone Acquisition, changes in Funds from Operations, unrealized gains and losses from risk management contracts, which fluctuate with changes in forward market prices and foreign exchange rates, foreign exchange gains and losses associated with the Company’s Senior Notes, fluctuations in natural gas and power pricing and the associated impact on energy-related production and operating costs, inflationary pressure and fluctuations in deferred tax expense or recovery.

Capital expenditures and total assets have fluctuated throughout the past eight quarters due to changes in the Company’s development capital spending levels which vary based on a number of factors, including the prevailing commodity price environment and the Pipestone Acquisition.

SPECIFIED FINANCIAL MEASURES

This MD&A makes reference to certain financial measures and ratios, including “Oil and natural gas sales, net of blending”, “Bitumen blend per bbl”, “Heavy oil, blended and raw per bbl”, “Crown royalties”, “Freehold royalties”, “Gross overriding royalties”, “Effective royalty rate”, “Production and operating – Energy”, “Production and operating – Non-energy”, “Production and operating – Energy ($/boe)”, “Production and operating – Non-energy ($/boe)”, “Transportation expense”, “Processing expense”, “Depletion expense”, “Depreciation and amortization expense”, “Operating Earnings”, “Funds from Operations”, “Free Cash Flow”, “Field Operating Income”, “Field Operating Netback”, “Field Operating Earnings”, and “Field Operating Earnings Netback”, which are not recognized measures under generally accepted accounting principles (“**GAAP**”) and do not have a standardized meaning prescribed by the Accounting Standards. Accordingly, the Company’s use of these terms may not be comparable to similarly defined measures presented by other companies. Management uses the terms “Field Operating Income”, “Field Operating Netback”, “Field Operating Earnings Netback”, “Operating Earnings”, “Field Operating Earnings”, “Funds from Operations” and “Free Cash Flow” for its own performance measures and to provide shareholders and potential investors with a measurement of the Company’s efficiency and its ability to generate the cash necessary to fund a portion of its future growth expenditures or to repay debt. Investors are cautioned that the specified financial measures should not be construed as an alternative to net income determined in accordance with GAAP as an indication of the Company’s performance.

Non-GAAP Financial Measures and Ratios

Non-GAAP financial measures and ratios are used internally by management to assess the performance of the Company. They also provide investors with meaningful metrics to assess the Company’s performance compared to other companies in the same industry. However, the Company’s use of these terms may not be comparable to similarly defined measures presented by other companies. Investors are cautioned that these measures should not be construed as an alternative to financial measures determined in accordance with GAAP and these measures should not be considered to be more meaningful than GAAP measures in evaluating the Company’s performance.

The term “**Oil and natural gas sales, net of blending**” is calculated by deducting purchased product and blending costs from oil and natural gas sales and sales of purchased product. Management uses this metric to isolate the revenue associated with the Company’s production after accounting for the unavoidable cost of blending. A quantitative reconciliation of Oil and natural gas sales, net of blending to the most directly comparable GAAP financial measure, Oil and natural gas sales, is contained under the heading “Revenue and Realized Prices - Oil and Natural Gas Sales Net of Blending” and “Segment Results” of this MD&A.

Oil and natural gas sales, net of blending, is also reflected on a per boe basis calculated using sales volumes. Management also calculates “**Bitumen blend per bbl**” and “**Heavy oil, blended and raw per bbl**” by deducting the associated purchased product and blending cost from oil and natural gas sales and sales of purchased product and dividing by the respective sales volume. This ratio is useful to management when analyzing realized pricing against benchmark commodity prices.

The term “**Crown royalties**” is the portion of royalty expense reflecting amounts paid for production on land where petroleum oil and natural gas rights are owned by government bodies. The term “**Freehold royalties**” is the portion of royalty expense reflecting amounts paid for production on land where petroleum oil and natural gas rights are owned by private individuals or entities. The term “**Gross overriding royalties**” is the portion of royalty expense reflecting amounts paid to third parties when the WCS Hardisty heavy oil benchmark exceeds US$60.00/bbl. Management uses these metrics to analyze royalties under different royalty regimes. A quantitative reconciliation of Crown royalties, Freehold royalties and Gross overriding royalties to the most directly comparable GAAP financial measure, royalties, is contained under the heading “Royalties” of this MD&A.

The term “**Effective royalty rate**” is calculated by dividing royalties by oil and natural gas sales and sales of purchased product, net of blending costs and purchased product. This metric allows management to analyze the movement of royalty expenses in relation to realized and benchmark commodity prices.

The term “**Production and operating – Energy**” is the portion of production and operating expenses reflecting the cost of gas and propane fuel, utilities and carbon tax incurred to operate facilities. This metric allows management to analyze the portion of production and operating expenses subject to non-controllable market prices. A quantitative reconciliation of Production and operating - Energy to the most directly comparable GAAP financial measure, Production and operating expenses, is contained under the heading "Production and operating expenses" of this MD&A.

The term “**Production and operating – Non-energy**” is the portion of production and operating expenses reflecting the cost of operating activities relating to the production of resources. This metric allows management to analyze the portion of production and operating expenses that is within the Company's control. A quantitative reconciliation of Production and operating – Non-energy to the most directly comparable GAAP financial measure, Production and operating expenses, is contained under the heading “Production and operating expenses” of this MD&A.

Production and operating – Energy and Production and operating – Non-energy are also reflected on a per boe basis calculated using sales volumes.

The term “**Transportation expense**” is the portion of Transportation and processing expenses reflecting the cost of transporting oil and natural gas to the sales point. The term “**Processing expense**” is the portion of Transportation and processing expenses reflecting costs incurred to refine produced volumes to meet sales specifications. Management uses these metrics to analyze the different fee structures to deliver product to a location and specification for sale. A quantitative reconciliation of Transportation expense and Processing expense to the most directly comparable GAAP financial measure, Transportation and processing expenses, is contained under the heading “Transportation and processing expenses” of this MD&A.

The term “**Depletion expense**” is the portion of Depletion, depreciation and amortization expense reflecting the cost of development of oil and natural gas reserves. The term “**Depreciation and amortization expense**” is the portion of Depletion, depreciation and amortization expense reflecting the cost of a fixed asset over its expected useful life. Management uses these metrics to analyze the capital cost of different property, plant and equipment types. A quantitative reconciliation of Depletion expense and Depreciation and amortization expense to the most directly comparable GAAP financial measure, Depletion, depreciation and amortization expense, is contained under the heading “Depletion, depreciation and amortization (“DD&A”)” of this MD&A.

“**Field Operating Income**” and “**Field Operating Netback**” are common metrics used in the oil and natural gas industry to assess the profitability and efficiency of the Company’s field operations.

“**Field Operating Earnings**” and “**Field Operating Earnings Netback**” are metrics used to assess the profitability of field operations inclusive of depletion, depreciation and amortization. Management finds this metric useful as it provides a full-cycle profitability measure at the field level that accounts for the capital intensive nature of the Company’s operations.

The following table reconciles “Field Operating Income”, “Field Operating Earnings”, “Field Operating Netback” and “Field Operating Earnings Netback” to the nearest GAAP measure.

	Three Months Ended			**Year Ended**	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Oil and natural gas sales	**1,292.8**	1,287.6	1,272.5	**5,336.4**	4,748.3
Sales of purchased products	**15.6**	11.3	44.4	**75.0**	46.3
Purchased product	**(16.1)**	(10.3)	(43.9)	**(75.0)**	(46.5)
Blending costs	**(267.7)**	(284.8)	(231.8)	**(1,081.5)**	(1,058.3)
Oil and natural gas sales, net of blending	**1,024.6**	1,003.8	1,041.2	**4,254.9**	3,689.8
Royalties	**208.5**	134.9	134.0	**662.7**	556.9
Production and operating	**197.2**	205.8	185.9	**811.7**	796.3
Transportation and processing	**144.2**	135.7	140.2	**577.0**	482.9
Field Operating Income	**474.7**	527.4	581.1	**2,203.5**	1,853.7
Depletion, depreciation and amortization	**196.3**	227.5	226.3	**873.5**	732.9
Field Operating Earnings	**278.4**	299.9	354.8	**1,330.0**	1,120.8
Field Operating Netback ($/boe)	**28.03**	31.09	35.42	**32.94**	32.57
Field Operating Earnings Netback ($/boe)	**16.44**	17.68	21.63	**19.88**	19.69

“**Operating Earnings**” is considered a key financial metric for evaluating the profitability of Strathcona’s principal business and is derived from income (loss) and comprehensive income (loss) adjusted for amounts which are considered non-recurring or not directly attributable to the Company’s operations.

“**Funds from Operations**” is used by management to analyze operating performance and provides an indication of the funds generated by Strathcona's principal business to either fund operating activities, re-invest to either maintain or grow the business or make debt repayments. Funds from Operations is derived from income (loss) and comprehensive income (loss) adjusted for non-cash items and transaction costs.

“**Free Cash Flow**” indicates funds available for deleveraging, funding future growth, or shareholder returns. Free Cash Flow is derived from income (loss) and comprehensive income (loss) adjusted for non-cash items, transaction costs, capital expenditures and decommissioning costs.

A quantitative reconciliation of Operating Earnings, Funds from Operations and Free Cash Flow to the most directly comparable GAAP financial measure, income (loss) and comprehensive income (loss), is set forth below.

	Three Months Ended			**Year Ended**	
($ millions, unless otherwise indicated)	**December 31, 2024**	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Income (loss) and comprehensive income (loss)	**87.9**	263.7	188.0	**603.7**	587.2
Loss (gain) on risk management contracts	**(10.2)**	(129.1)	16.6	**44.0**	(69.6)
Foreign exchange (gain) loss	**47.7**	(20.9)	(6.8)	**68.2**	(22.1)
Transaction related costs	**0.3**	(1.3)	0.3	**1.0**	3.8
Unrealized (gain) loss on Sable remediation fund	**—**	(0.3)	(0.2)	**(0.1)**	(0.2)
Loss on settlement of other obligation	**—**	—	4.4	**4.4**	—
Deferred tax expense	**64.3**	90.0	63.1	**249.3**	296.2
Operating Earnings	**190.0**	202.1	265.4	**970.5**	795.3
Depletion, depreciation and amortization	**196.3**	227.5	226.3	**873.5**	732.9
Finance costs	**21.0**	21.6	21.9	**88.3**	75.3
Decommissioning government grant	**—**	—	—	**0.2**	(0.3)
(Loss) gain on risk management contracts - realized	**(5.4)**	19.5	(94.7)	**(107.0)**	(42.4)
Realized loss on deferred premium settlement	**—**	—	112.4	**112.4**	—
Foreign exchange (loss) gain - realized	**3.6**	0.1	(2.6)	**(0.5)**	1.4
Funds from Operations	**405.5**	470.8	528.7	**1,937.4**	1,562.2
Capital expenditures	**(392.5)**	(306.2)	(319.6)	**(1,295.6)**	(1,026.8)
Decommissioning costs	**(12.7)**	(13.8)	(8.5)	**(35.7)**	(37.9)
Free Cash Flow	**0.3**	150.8	200.6	**606.1**	497.5

"PDP Recycle Ratio”[1] is calculated by dividing the Organic Operating Netback by PDP Finding and Development Costs (**“PDP F&D”**[1]). PDP Recycle Ratio is used to measure the profit per barrel of oil to the cost of finding and developing that barrel of oil.

“Organic Operating Netback”[1] is used to assess the profitability and efficiency of Strathcona’s field operations before the impact of acquisitions.

A quantitative reconciliation of “Organic Operating Netback” to the most comparable GAAP measure, "Oil and natural gas sales”, is set forth below:

($ millions, unless otherwise indicated)	Year Ended December 31, 2024
Oil and natural gas sales	**5,336.4**
Sales of purchased products	**75.0**
Purchased product	**(75.0)**
Blending costs	**(1,081.5)**
Oil and natural gas sales, net of blending	**4,254.9**
Royalties	**662.7**
Production and operating	**811.7**
Transportation and processing	**577.0**
Field Operating Income	**2,203.5**
Operating income from properties acquired in the year	**-**
Organic Operating Income	**2,203.5**
Sales volumes (boe/d)	**182,794**
Less: sales volumes from properties acquired in the year (boe/d)	**-**
Organic Sales volumes (boe/d)	**182,794**
Organic Operating Netback ($/boe)	**32.94**

“PDP F&D Costs”(1) are calculated as Organic Capex plus changes in PDP future development costs (2024 - $56.0 million), divided by PDP reserve additions for the year (2024 – 95.7 MMboe), excluding the impact of acquisitions and dispositions. Management uses PDP F&D costs as a measure of capital efficiency for organic reserves development.

“Organic Capex”(1) is calculated as property, plant and equipment expenditures excluding capitalized overhead, expenditures on corporate assets and property, plant and equipment expenditures on acquired assets.

A quantitative reconciliation of “Organic Capex” to the most comparable GAAP measure, “Property, plant and equipment expenditures”, is set for below:

($ millions)	Year Ended December 31, 2024
Property, plant and equipment expenditures	**1,295.6**
Less: capitalized overhead	**(52.1)**
Less: expenditures on corporate assets	**(9.0)**
Less: property, plant and equipment expenditures on assets acquired in the year	**—**
Organic Capex	**1,234.5**

(1) Pertains to the Message to Shareholders included in Strathcona’s 2024 Annual Report which can be found at www.sedarplus.ca and www.strathconaresources.com.

APPLICATION OF CRITICAL ACCOUNTING ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimates that differ materially from current estimates. The Company’s use of estimates and judgements in preparing the annual financial statements are discussed in Note 2 of the annual financial statements.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure controls and procedures ("**DC&P**"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings (“**NI 52-109**”), are designed to provide reasonable assurance that information required to be disclosed in the Company’s annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Executive Chairman and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Executive Chairman and the Chief Financial Officer of Strathcona evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company’s DC&P as at December 31, 2024. Based on that evaluation, the Executive Chairman and the Chief Financial Officer concluded that Strathcona's DC&P were effective as at December 31, 2024.

Internal control over financial reporting ("**ICFR**") is a set of processes designed to provide reasonable assurance that all assets are safeguarded, transaction are appropriately authorized, and facilitate the preparation of relevant, timely and reliable information. Because of its inherent limitations, ICFR, may not prevent or detect misstatements. Management has assessed the effectiveness of the Company's ICFR as defined in Canada by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organization of the Treadway Commission. Management concluded that the Company's ICFR was effective as of December 31, 2024. There were no changes made to the Company's ICFR during the year ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect, the Company's ICFR.

ADVISORIES REGARDING OIL & GAS INFORMATION

This MD&A contains various references to the abbreviation “**boe**” which means barrels of oil equivalent. All boe conversions in this MD&A are derived by converting gas to oil at the ratio of six thousand cubic feet (“**mcf**”) of natural gas to one barrel (“**bbl**”) of crude oil. Boe may be misleading, particularly if used in isolation. A boe conversion rate of 1 bbl : 6 mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio of oil compared to natural gas based on currently prevailing prices is significantly different than the energy equivalency ratio of 1 bbl : 6 mcf, utilizing a conversion ratio of 1 bbl : 6 mcf may be misleading as an indication of value. References to “liquids” in this MD&A refer to, collectively, bitumen, heavy oil, condensate and light oil and other natural gas liquids (“**NGL**”) (comprised of ethane, propane and butane only).

National Instruments 51-101 - *Standards of Disclosure for Oil and Gas Activities* includes condensate within the natural gas liquids product type. The Company has disclosed condensate as combined with light oil and separately from other natural gas liquids in this MD&A since the price of condensate as compared to other natural gas liquids is currently significantly higher and the Company believes that this presentation provides a more accurate description of its operations and results therefrom. References to “oil and condensate" in this MD&A refer to, collectively, light and medium crude oil, heavy crude oil, bitumen and natural gas liquids. References to "natural gas" in this MD&A refer to conventional natural gas.

The Company’s annual and quarterly average daily production volumes for 2024 and 2023, and the references to “natural gas”, “crude oil” and “condensate”, reported in this MD&A consist of the following product types, as defined in NI 51-101 and using a conversion ratio of 6 mcf : 1 bbl where applicable:

	Three Months Ended			Year Ended	
	December 31, 2024	December 31, 2023	September 30, 2024	**December 31, 2024**	December 31, 2023
Cold Lake segment					
Heavy crude oil (bbl/d)	**—**	—	—	**—**	—
Light and medium crude oil (bbl/d)	**—**	—	—	**—**	—
Total crude oil (bbl/d)	**—**	—	—	**—**	—
Bitumen (bbl/d)	**59,732**	59,845	58,610	**59,516**	55,768
NGLs (bbl/d)	**—**	—	—	**—**	—
Total liquids (bbl/d)	**59,732**	59,845	58,610	**59,516**	55,768
Conventional natural gas (mcf/d)	**—**	—	—	**—**	—
Total (boe/d)	**59,732**	59,845	58,610	**59,516**	55,768
Lloydminster segment					
Heavy crude oil (bbl/d)	**50,997**	52,736	50,494	**51,107**	53,707
Light and medium crude oil (bbl/d)	**64**	40	30	**42**	42
Total crude oil (bbl/d)	**51,061**	52,776	50,524	**51,149**	53,749
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**4**	—	2	**2**	1
Total liquids (bbl/d)	**51,065**	52,776	50,526	**51,151**	53,750
Conventional natural gas (mcf/d)	**1,295**	1,260	1,150	**1,232**	1,080
Total (boe/d)	**51,281**	52,987	50,718	**51,357**	53,930
Montney segment					
Heavy crude oil (bbl/d)	**—**	—	—	**—**	—
Light and medium crude oil (bbl/d)	**553**	540	615	**609**	601
Total crude oil (bbl/d)	**553**	540	615	**609**	601
Bitumen (bbl/d)	**—**	—	—	**—**	—
NGLs (bbl/d)	**33,122**	30,509	30,553	**31,227**	20,388
Total liquids (bbl/d)	**33,675**	31,049	31,168	**31,836**	20,989
Conventional natural gas (mcf/d)	**255,091**	253,101	226,431	**242,224**	148,635
Total (boe/d)	**76,190**	73,233	68,907	**72,207**	45,762
Consolidated					
Heavy crude oil (bbl/d)	**50,997**	52,736	50,494	**51,107**	53,707
Light and medium crude oil (bbl/d)	**617**	580	645	**651**	642
Total crude oil (bbl/d)	**51,614**	53,316	51,139	**51,758**	54,349
Bitumen (bbl/d)	**59,732**	59,845	58,610	**59,516**	55,768
NGLs (bbl/d)	**33,126**	30,509	30,555	**31,229**	20,389
Total liquids (bbl/d)	**144,472**	143,670	140,304	**142,503**	130,506
Conventional natural gas (mcf/d)	**256,386**	254,361	227,581	**243,456**	149,715
Total (boe/d)	**187,203**	186,064	178,235	**183,080**	155,459

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information within the meaning of applicable securities laws. The forward-looking information in this MD&A is based on Strathcona's current internal expectations, estimates, projections, assumptions and beliefs. Such forward-looking information is not a guarantee of future performance and involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Company believes the material factors, expectations and assumptions reflected in the forward-looking information are reasonable as of the time of such information, but no assurance can be given that these factors, expectations and assumptions will prove to be correct, and such forward-looking information included in this MD&A should not be unduly relied upon.

The use of any of the words "expect", "anticipate", "estimate", "objective", "ongoing", "may", "will", "project", "believe", "depends", "could" and similar expressions are intended to identify forward-looking information. In particular, but without limiting the generality of the foregoing, this MD&A contains forward-looking information pertaining to the following: the Company's business strategy and future plans; the Company's 2025 production and capital spending guidance; the declaration and payment of dividends, including the amount and timing thereof; expected impacts of tariffs on Strathcona's operations, including Local Sales, and the effectiveness of Strathcona's mitigation measures; the Company's use of hedging arrangements; the Company's ability to meet current and future obligations, including making scheduled principal and interest payments, to fund planned capital expenditures and to fund the other needs of the business; future liquidity and financial capacity; anticipated proceeds from financial instruments, including commodity contracts; and sources of funding for the Company's capital program, working capital deficiency and the terms of Strathcona's future contractual obligations, including its obligations under the Credit Agreement and Senior Notes and oil and natural gas prices and differentials.

All forward-looking information reflects Strathcona's beliefs and assumptions based on information available at the time the applicable forward-looking information is disclosed and in light of the Company's current expectations with respect to such things as: the success of Strathcona's operations and growth and expansion projects; expectations regarding production growth, future well production rates and reserve volumes; expectations regarding Strathcona's capital program; Strathcona's ability to declare and pay dividends; expectations regarding the impact of tariffs on Strathcona's operations and its ability to effectively mitigate the impact thereof; the outlook for general economic trends, industry trends, prevailing and future commodity prices, foreign exchange rates and interest rates; prevailing and future royalty regimes and tax laws; future well production rates and reserve volumes; fluctuations in energy prices based on worldwide demand and geopolitical events; the impact of inflation; the integrity and reliability of Strathcona's assets; decommissioning obligations; Strathcona's ability to comply with its financial covenants; and the governmental, regulatory and legal environment, including expectations regarding the current and future carbon tax regime and regulations; ability to obtain federal CCS investment tax credit and other grants to fund Strathcona's portion of the CCS investment under the arrangement. In addition, certain forward-looking information with respect to the Company's 2025 guidance assumes commodity prices and exchange rates of: US$70 / bbl WTI, US$13 / bbl WCS-WTI differential, 1.38 USD-CAD and C$3 / GJ AECO. Management believes that its assumptions and expectations reflected in the forward-looking information contained herein are reasonable based on the information available on the date such information is provided and the process used to prepare the information. However, it cannot assure readers that these expectations will prove to be correct.

The forward-looking information included in this MD&A is not a guarantee of future performance and involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information, including, without limitation: changes in commodity prices; changes in the demand for or supply of Strathcona's products; the continued impact, or further deterioration, in global economic and market conditions, including from inflation and/or certain geopolitical conflicts, such as the ongoing Russia/Ukraine conflict, the conflict in the Middle East, and other heightened geopolitical risks, including the imposition of tariffs or other trade barriers, and the ability of the Company to carry on operations as contemplated in light of the foregoing; determinations by the Organization of the Petroleum Exporting Countries and other countries as to production levels; unanticipated operating results or production declines; changes in tax or environmental laws, climate change, royalty rates or other regulatory matters; changes in Strathcona's development plans or by third party operators of Strathcona's properties; failure to achieve anticipated results of its operations; competition from other producers; inability to retain drilling rigs and other services; failure to realize the anticipated benefits of the Company's acquisitions or corporate reorganizations; incorrect assessment of the value of acquisitions; delays resulting from or inability to obtain required regulatory approvals; the risk that the arrangement with Canada Growth Fund may not provide the anticipated benefits to Strathcona; the risk that Canada Growth Fund may not meet its funding obligations under the terms of the arrangement; the risk that the CCS facilities may not reduce emissions attributable to Strathcona's operations; the risk that the CCS investment tax credit and other grants may not be available or available on the terms expected; increased debt levels or debt service requirements; inflation; changes in foreign exchange rates; inaccurate estimation of Strathcona's oil and gas reserve and contingent resource volumes; limited, unfavourable or a lack of access to capital markets or other sources of capital; increased costs; a lack of adequate insurance coverage; the impact of competitors; and the other factors discussed under the "Risk Factors" section in the Company's Management's Discussion and Analysis and Annual Information Form for the year ended December 31, 2024, a copy of each of which is available under the Company's profile on SEDAR+ at www.sedarplus.ca.

Declaration of dividends is at the sole discretion of the board of directors of Strathcona and will continue to be evaluated on an ongoing basis. There are numerous factors that may result in Strathcona changing, suspending or discontinuing its quarterly dividends, including changes to its free cash flow, operating results, capital requirements, financial position, debt levels, market conditions or corporate strategy and the need to comply with requirements under the Credit Agreement and applicable laws respecting the declaration and payment of dividends. There are no assurances as to the continuing declaration and payment of future dividends or the amount or timing of any such dividends.

The purpose of the capital expenditure guidance is to assist readers in understanding Strathcona's expected and targeted financial position and performance, and this information may not be appropriate for other purposes.

The foregoing risks should not be construed as exhaustive. The forward-looking information contained in this MD&A speaks only as of the date of this MD&A and Strathcona does not assume any obligation to publicly update or revise such forward-looking information to reflect new events or circumstances, except as may be required pursuant to applicable laws. Any forward-looking information contained herein is expressly qualified by this cautionary statement.

ADDITIONAL INFORMATION

Additional information about Strathcona, including Strathcona's Annual Information Form for the year ended December 31, 2024 and the annual financial statements, can be found at: www.sedarplus.ca and www.strathconaresources.com.

STRATHCONA
RESOURCES LTD

CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEARS ENDED DECEMBER 31, 2024 AND 2023

Independent Auditor's Report

To the Shareholders and the Board of Directors of
Strathcona Resources Ltd.

Opinion

We have audited the consolidated financial statements of Strathcona Resources Ltd. (the "Company"), which comprise the consolidated statements of financial position as at December 31, 2024 and 2023, and the consolidated statements of income and comprehensive income, changes in equity and cash flows for the years then ended, and notes to the consolidated financial statements, including material accounting policy information (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2024 and 2023, and its financial performance and its cash flows for the years then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matter

A key audit matter is a matter that, in our professional judgment, was of most significance in our audit of the consolidated financial statements for the year ended December 31, 2024. This matter was addressed in the context of our audit of the consolidated financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on this matter.

Property Plant and Equipment – Oil and natural gas properties — Refer to Notes 3 and 5 to the financial statements

Key Audit Matter Description

The Company's property, plant and equipment includes oil and natural gas properties. Oil and natural gas properties, including related facilities are depleted using the unit-of-production method ("depletion") based on total estimated proved plus probable reserves. The Company engages independent reserve engineers to estimate oil and natural gas reserves using estimates, assumptions and engineering data. The development of the Company's proved plus probable oil and natural gas reserves that are used to determine depletion requires management to make significant estimates and assumptions related to future oil and natural gas prices, reserves, and future development costs.

Given the significant judgments made by management related to oil and natural gas prices, reserves, and future development costs, these estimates and assumptions are subject to a high degree of estimation uncertainty. Auditing these estimates and assumptions required auditor judgment in applying audit procedures and in evaluating the results of those procedures.

How the Key Audit Matter Was Addressed in the Audit

Our audit procedures related to future oil and natural gas prices, reserves, and future development costs used to measure oil and natural gas properties included the following, among others:

- Evaluated oil and natural gas prices by independently developing a reasonable range of forecasts based on reputable third-party forecasts and market data and comparing those to the oil and natural gas prices selected by management.
- Evaluated the Company's independent reserve engineers by examining reports and assessing their scope of work and findings and assessing the competence, capability and objectivity by evaluating their relevant professional qualifications and experience.
- Evaluated the reasonableness of reserves by testing the source financial information underlying the reserves and comparing the reserve volumes to historical production volumes.
- Evaluated the reasonableness of future development costs by testing the source financial information underlying the estimate, comparing future development costs to historical results, and evaluating whether they are consistent with evidence obtained in other areas of the audit.

Other Information

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

- Management's Discussion and Analysis
- The information, other than the financial statements and our auditor's report thereon, in the Annual Report.

Our opinion on the 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 financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

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

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

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

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

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

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an 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 GAAS 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 financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our 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 financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Plan and perform the group audit to obtain sufficient appropriate audit evidence regarding the financial information of the entities or business units within the Company as a basis for forming an opinion on the financial statements. We are responsible for the direction, supervision and review of the audit work performed for purposes 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.

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

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

The engagement partner on the audit resulting in this independent auditor’s report is Mandeep Singh.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Alberta
March 4, 2025

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

Cdn$ millions

As at	Note	December 31, 2024	December 31, 2023
Assets			
Current			
Accounts receivable	**14**	**348.2**	334.6
Inventory		**47.8**	43.3
Prepaid expenses and deposits		**30.0**	28.1
Cross-currency swap asset	**6, 14**	**28.6**	—
Other assets		**4.5**	—
Risk management asset	**14**	**47.0**	41.3
Total current assets		**506.1**	447.3
Property, plant and equipment	**5**	**10,456.4**	10,030.1
Other assets		**15.0**	19.5
Total assets		**10,977.5**	10,496.9
Liabilities			
Current			
Accounts payable and accrued liabilities		**918.7**	783.8
Deferred revenue		**57.4**	37.5
Cross-currency swap liability	**6, 14**	**—**	39.6
Lease and other obligations	**7**	**64.5**	43.8
Decommissioning provision	**8**	**40.9**	36.6
Risk management liability	**14**	**44.6**	125.4
Total current liabilities		**1,126.1**	1,066.7
Debt	**6**	**2,461.6**	2,665.0
Lease and other obligations	**7**	**282.5**	362.4
Decommissioning provision	**8**	**249.8**	314.7
Deferred tax liability	**13**	**990.7**	741.4
Risk management liability	**14**	**43.1**	19.6
Total liabilities		**5,153.8**	5,169.8
Equity			
Share capital	**12**	**3,590.5**	3,590.5
Contributed surplus		**49.9**	49.9
Retained earnings		**2,183.3**	1,686.7
Total equity		**5,823.7**	5,327.1
Total liabilities and equity		**10,977.5**	10,496.9

Commitments and contingencies (Note 15)
See accompanying notes to the consolidated financial statements.

/s/ Cody Church
Cody Church, Director

/s/ Navjeet (Bob) Singh Dhillon
Navjeet (Bob) Singh Dhillon, Director

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

Cdn$ millions, except per share amounts

For the Year Ended December 31,	Note	2024	2023
Revenues and other income			
Oil and natural gas sales	9	**5,336.4**	4,748.3
Sale of purchased products		**75.0**	46.3
Royalties		**(662.7)**	(556.9)
Oil and natural gas revenues		**4,748.7**	4,237.7
(Loss) gain on risk management contracts	14	**(44.0)**	69.6
Other income		**0.1**	1.0
		4,704.8	4,308.3
Expenses			
Purchased product		**75.0**	46.5
Blending costs		**1,081.5**	1,058.3
Production and operating		**811.7**	796.3
Transportation and processing		**577.0**	482.9
General and administrative		**101.1**	91.9
Interest	6	**170.2**	206.2
Transaction related costs	4	**1.0**	3.8
Finance costs	10	**88.3**	75.3
Depletion, depreciation and amortization	5	**873.5**	732.9
Foreign exchange loss (gain)	11	**68.2**	(22.1)
Unrealized gain on Sable remediation fund		**(0.1)**	(0.2)
		3,847.4	3,471.8
Loss on settlement of other obligations	7	**(4.4)**	—
Income before income taxes		**853.0**	836.5
Income tax expense	13	**249.3**	249.3
Income and comprehensive income		**603.7**	587.2
Net income per share			
Basic and Diluted	12	**2.82**	2.94

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
Cdn$ millions

	Note	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
Balance as at December 31, 2022		3,052.8	49.9	1,099.5	4,202.2
Equity issuance - employees		0.7	—	—	0.7
Equity issuance – Pipestone Acquisition	4	537.0	—	—	537.0
Income and comprehensive income		—	—	587.2	587.2
Balance as at December 31, 2023		**3,590.5**	**49.9**	**1,686.7**	**5,327.1**
Dividends	12	—	—	(107.1)	**(107.1)**
Income and comprehensive income		—	—	603.7	**603.7**
Balance as at December 31, 2024		**3,590.5**	**49.9**	**2,183.3**	**5,823.7**

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS
Cdn$ millions

For the Year Ended December 31,	Note	2024	2023
Cash flow from (used in) operating activities			
Net income		**603.7**	587.2
Items not involving cash	**17**	**1,332.7**	971.1
Decommissioning costs	**8**	**(35.7)**	(37.9)
Changes in non-cash working capital	**17**	**92.1**	4.3
		1,992.8	1,524.7
Cash flow from (used in) financing activities			
Draw of debt	**6, 11**	**—**	375.3
Repayment of debt	**6, 11**	**(339.2)**	(700.0)
Repayment of acquired debt	**4**	**—**	(179.2)
Lease and other obligations	**7**	**(236.8)**	(52.3)
Debt issuance costs		**(11.4)**	(4.7)
Issuance of common shares, net of share purchases		**—**	0.7
Cash dividends paid		**(107.1)**	—
Changes in non-cash working capital	**17**	**—**	0.6
		(694.5)	(559.6)
Cash flow from (used in) investing activities			
Property, plant and equipment expenditures	**5**	**(1,295.6)**	(1,026.8)
Property acquisitions and dispositions, net	**5**	**(41.0)**	—
Capitalized transaction costs	**4**	**—**	(23.4)
Changes in non-cash working capital	**17**	**38.3**	50.8
		(1,298.3)	(999.4)
Change in cash		**—**	(34.3)
Cash, beginning of period		**—**	34.3
Cash, end of period		**—**	—
Cash interest paid		**175.9**	214.6

See accompanying notes to the consolidated financial statements.

1. DESCRIPTION OF BUSINESS

Strathcona Resources Ltd. ("**Strathcona**" or the "**Company**") is a corporation resulting from the amalgamation of Strathcona Resources Ltd. and Pipestone Energy Corp. ("**Pipestone**") on October 3, 2023, pursuant to a plan of arrangement under the Business Corporations Act (Alberta) (the "**ABCA**"), (the "**Arrangement**"). Upon completion of the Arrangement, Strathcona's Common Shares were listed on the TSX under the trading symbol "SCR" and commenced trading on October 5, 2023. Strathcona exists under, and is governed by, the provisions of the ABCA. These consolidated financial statements reflect the historical financial information of Strathcona Resources Ltd., and commencing on October 3, 2023, also reflect the results of Pipestone.

At December 31, 2024, approximately 90.8% of the Company's shares were owned by certain limited partnerships comprising of Waterous Energy Fund and its affiliates (collectively, "**WEF**").

On January 31, 2025, two of the limited partnerships comprising WEF completed a share pass-through transaction resulting in the disposition of 24,010,576 common shares of Strathcona by WEF to their limited partners. Following completion of this transaction, WEF owns approximately 79.6% of the Company's shares.

Strathcona is engaged in the exploration, acquisition, development and production of petroleum and natural gas reserves in western Canada. The consolidated financial statements (the "**financial statements**") include the results of Strathcona Resources Ltd. and its wholly owned subsidiaries.

The Company's head office is located at Suite 1900, 421 – 7 Avenue SW, Calgary, Alberta, Canada, T2P 4K9.

2. BASIS OF PREPARATION

Preparation

These financial statements have been prepared in accordance with IFRS® Accounting Standards (the "**Accounting Standards**") as issued by the International Accounting Standards Board ("**IASB**"). These financial statements were authorized for issue by the Board of Directors on March 4, 2025.

These financial statements have been prepared on the historical cost basis except for those items that are presented at fair value as detailed in the accounting policies disclosed in Note 3.

In these financial statements, all amounts are expressed in Canadian dollars ("**CAD**" or "**C$**") unless otherwise indicated, which is the Company's functional and presentation currency.

Use of estimates and judgments

The preparation of the financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from those estimated.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected.

Information about certain areas of estimation uncertainty and critical judgments in applying accounting policies that affect amounts recognized in these financial statements is as follows:

Business combinations

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

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

*Identification of cash-generating units ("**CGUs**")*

For the purpose of impairment testing, assets that cannot be tested individually are grouped together into CGUs, which are the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. Determination of what constitutes a CGU is subject to management's judgment. Factors considered in the classification include the integration between assets, shared infrastructure, the existence of common sales points, geography, geological structure and the manner in which management monitors and makes decisions about its operations. As such, the determination of a CGU may have an impact on the carrying value of the Company's assets in future periods and current periods.

Oil and natural gas reserves

Proved and probable reserves have been estimated by external experts and are based on a number of underlying assumptions including oil and natural gas prices, future costs, oil and natural gas in place and reservoir performance, all of which are inherently uncertain. Established industry techniques are used to generate these estimates, however, the reserves that are ultimately recovered cannot be known with certainty until the end of the field's life. Changes in reserves estimates could have a material impact on unit-of-production rates used for depletion, timing of decommissioning obligations and impairment of oil and natural gas properties. The Company's reserves are evaluated annually and reported to the Company by its independent qualified reserves evaluator.

Recoverability of property, plant and equipment

The Company has significant investments in property, plant and equipment. Changes in circumstances or expectations of future performance of an individual asset may be an indicator that the asset is impaired requiring the carrying value to be written down to its recoverable amount. Evaluating whether an asset is impaired requires a high degree of judgment in estimating relevant future cash flows, based on assumptions about the future market prices, production output and discount rates.

*Exploration and evaluation ("**E&E**") assets*

The accounting for E&E assets requires management to make judgments as to whether E&E activities have discovered a sufficient amount of economically recoverable reserves, which requires the quantity and realizable value of such reserves to be estimated and could be impacted by a shift in demand as global energy markets transition to a lower carbon-based economy. Previous estimates are sometimes revised as new information becomes available.

E&E assets remain capitalized as long as sufficient progress is being made in assessing whether the recovery of the reserves is technically feasible and commercially viable. The concept of "sufficient progress" is a judgmental area, and it is possible to have E&E assets remain classified as such for several years while additional E&E activities are carried out or the Company seeks government, regulatory, or internal approval for development plans. E&E assets are subject to ongoing management review to confirm the continued intent to establish the technical feasibility and commercial viability of the discovery. When management is making this assessment, changes to project economics, expected capital investments and production costs, results of other operators in the region, and access to infrastructure and potential infrastructure expansions are important factors considered.

Decommissioning provision

The Company has obligations in respect of decommissioning its oil and natural gas properties. The present value of the obligation is calculated based on estimated future cash flows, timing of remediation activities, estimated inflation rate and the credit adjusted discount rate applied. Assumptions, based on current economic factors, have been made to estimate the future liability. However, the actual cost of decommissioning is uncertain and cost estimates may change in response to numerous factors including changes in legal requirements, technological advances, inflation and the timing of expected decommissioning and restoration.

Leases

Management applies judgment in reviewing each of its contractual arrangements to determine whether the arrangement contains a lease within the scope of IFRS 16 - Leases ("**IFRS 16**"). Leases that are recognized are subject to further management judgment and estimation in various areas specific to the arrangement. The estimates and assumptions related to the application of IFRS 16 include:

- Incremental borrowing rate: The incremental borrowing rates are based on judgments including economic environment, term, currency and the underlying risk inherent to the asset. The carrying balance of the right-of-use

("**ROU**") assets, lease obligations and the resulting accretion and depreciation expense, may differ due to changes in the market conditions and lease term.

- Lease term: Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

Financial Instruments

The estimated fair value of financial instruments is reliant upon a number of estimated variables including forward curves for commodity prices and foreign exchange rates. A change in these factors could result in a change to the overall estimated valuation of the instrument.

Income taxes

The calculation of deferred income tax assets and liabilities is based on management's interpretation of applicable laws, regulations, relevant court decisions and estimates regarding the timing of reversals of temporary differences.

3. MATERIAL ACCOUNTING POLICY INFORMATION

Basis of consolidation

The financial statements include accounts of the Company and its subsidiaries. Subsidiaries are entities controlled by the Company. Subsidiaries are consolidated from the date that control commences until the date that control ceases. The accounting policies of subsidiaries align with the policies adopted by the Company. Intercompany balances and transactions, and any unrealized income and expenses arising from intercompany transactions, are eliminated in preparing the financial statements.

Foreign currency

Transactions in foreign currencies are translated to Canadian dollars at exchange rates on the respective dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to Canadian dollars at the period end exchange rate. Non-monetary assets that are measured in a foreign currency at historical cost are translated using the exchange rate at the date of the transaction. Foreign currency differences arising on translation are recognized in earnings and are reported on a net basis.

Inventory

Inventory consists of raw crude oil, diluent and blended crude oil at the Company's facilities, and in-transit via pipeline and rail. Inventory is carried at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and includes direct purchase costs and costs of production (royalties, production and operating costs, transportation and processing costs, blending costs and depletion of oil and natural gas properties). Net realizable value is the estimated selling price in the ordinary course of business, less applicable selling expenses.

Property, plant and equipment

(i) General

Oil and natural gas properties and corporate assets, collectively, "property, plant and equipment", are measured at cost less accumulated depletion, depreciation and amortization and accumulated impairment losses.

(ii) Oil and natural gas properties

The initial cost of an asset comprises of its purchase price or construction cost, any costs directly attributable to bringing the asset into operation and the initial estimate of a decommissioning obligation.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts are recognized as oil and natural gas properties only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in earnings as incurred. Such capitalized expenditures generally represent costs incurred in developing proved and/or probable reserves and bringing on or enhancing production from such reserves. The carrying amount of any significant replaced or sold component is derecognized. The costs of the day-to-day servicing of oil and natural gas properties are recognized in earnings as incurred.

When significant parts of an item of oil and natural gas properties have different useful lives, they are accounted for as separate items.

Gains and losses on disposal of an item of oil and natural gas properties are determined by comparing the proceeds from disposal with the carrying amount of oil and natural gas properties and are recognized in earnings.

(iii) Corporate assets

Costs associated with intangible assets, office furniture, fixtures, leasehold improvements, information technology and other corporate assets are carried at cost and depreciated based on the estimated useful lives of the assets.

Corporate assets also includes the recognition of ROU assets, in accordance with IFRS 16. ROU assets are depreciated on a straight-line basis over the shorter of the asset's useful life and the lease term. Depreciation on ROU assets is recognized in depletion, depreciation and amortization.

(iv) Non-monetary exchanges

Non-monetary exchanges of oil and natural gas properties are measured at fair value, unless the transaction lacks commercial substance or the fair value of the asset received or given up cannot be reliably measured. When fair value is not used, the carrying amount of the asset given up is used as the cost of the asset acquired.

(v) Depletion and depreciation

Oil and natural gas properties, including related facilities, are depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved and probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil. These estimates are prepared by independent reserve engineers at least annually. Oil and natural gas properties are grouped with assets that are dedicated to serving the same reserves.

The estimated useful lives of depreciable assets are as follows:

Furniture and office equipment	30% declining balance
Computer hardware and systems software	30% declining balance
Vehicles	30% declining balance
Facilities	Straight-line over 15 - 20 years
Computer application software	Straight-line over 1 year
Leasehold improvements	Straight-line over the term of the lease

Exploration for and evaluation of mineral resources

E&E costs incurred prior to obtaining the legal right to explore are expensed. Costs incurred after the legal right to explore an area has been obtained are capitalized as exploration and evaluation assets. These costs can include license acquisition, geological and geophysical, drilling, sampling and other directly attributable internal costs. Exploration and evaluation assets are not depreciated and are accumulated in cost centers until technical feasibility and commercial viability of the project, area or field is determined or the assets are determined to be impaired. Technical feasibility and commercial viability of E&E assets is dependent upon the assignment of a sufficient amount of economically recoverable crude oil, condensate, natural gas, and natural gas liquids reserves and available infrastructure to support commercial development, as well as obtaining the appropriate internal and external approvals.

Once technical feasibility and commercial viability has been established for a project, area or field, the exploration and evaluation assets attributable to those reserves are first assessed for impairment by comparing the carrying amount to the greater of the assets' fair value less costs of disposal or value in use and are then transferred from exploration and evaluation assets to oil and natural gas properties. If a decision is made by the Company not to continue an E&E project, the E&E is derecognized and all associated costs are charged to the statement of comprehensive income in E&E expense at that time.

Impairment of non-financial assets

CGUs are reviewed at each reporting date to determine whether there is any indication that the carrying amount may exceed its recoverable amount. If any such indication exists, an impairment test is performed by comparing the CGU's carrying value to its estimated recoverable amount. The recoverable amount of a CGU is the greater of its value in use and its fair value less costs of disposal. An impairment loss is recognized if the carrying amount of a CGU exceeds its estimated recoverable amount.

Impairment losses are recognized in earnings. Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the CGU on a pro rata basis.

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 may be reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset’s carrying amount does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

Business combinations

The acquisition method of accounting is used to account for business combinations. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the date of the exchange. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured initially at their fair values at the acquisition date, irrespective of the extent of any minority interest. The excess of the cost of acquisition over the fair value of the Company's share of the net fair value of the identifiable assets, liabilities and contingent liabilities is recorded as goodwill. If the cost of an acquisition is less than the fair value of the net assets of the subsidiary acquired, the difference is recognized immediately in earnings.

Transaction costs that are incurred in connection with a business combination, other than those associated with the issuance of debt or equity securities, are recognized in earnings.

There is an option to apply a concentration test that permits a simplified assessment of whether an acquired set of activities and assets is in fact a business. The optional concentration test is met if substantially all of the fair value of the assets acquired is concentrated in a single identifiable asset or group of similar identifiable assets. An entity may make such an election separately for each transaction or other event. If the concentration test is met, the set of activities and assets is determined not to be a business and no further assessment is needed.

Leases

On the date that a leased asset becomes available for use, the Company recognizes an ROU asset and a corresponding lease obligation. Accretion expense associated with the lease obligation is charged to earnings over the lease period with a corresponding increase to the lease obligation. The lease obligation is reduced as payments are made against the principal portion of the lease. The ROU asset is depreciated over the shorter of the asset’s useful life and the lease term on a straight-line basis. Depreciation of the ROU asset is recognized in depletion, depreciation and amortization.

A lease obligation is measured at the commencement date of the lease term at the present value of the lease payments that have not yet been paid as of that date. The ROU asset is measured at cost, which is comprised of the amount of the initial measurement of the lease obligation, less any incentives received net of any onerous contracts, plus any lease payments made at, or before, the commencement date and initial direct costs and asset restoration costs, if any.

The rate implicit in the lease is used to determine the present value of the liability and ROU asset arising from a lease, unless this rate is not readily determinable, in which case the Company’s incremental borrowing rate is used. Generally, the Company uses its incremental borrowing rate as the discount rate.

The lease obligation is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company’s estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. A corresponding adjustment is made to the carrying amount of the ROU asset, or is recorded in the earnings if the carrying amounts of the ROU asset has been reduced to $nil.

Provisions

(i) General

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 pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability. The discount rate is adjusted for the Company’s credit risk. Provisions are not recognized for future operating losses. The unwinding of the discount is recognized as a finance cost.

(ii) Decommissioning provision

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

Decommissioning provisions are measured at their present value at the statement of financial position date, based on management's best estimate of the expenditures required to settle the obligation at the end of the asset's useful life. On a periodic basis, management reviews these estimates and changes are applied prospectively. Subsequent to the initial measurement, the provision is adjusted at the end of each 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 is recognized as finance costs (accretion expense) whereas increases/decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning provisions are charged against the provision.

Financial instruments

Financial assets and liabilities are recognized when the Company becomes a party to the contractual provisions of the instrument. Financial assets are derecognized when the rights to receive cash flows from the assets have expired, or when the Company has transferred substantially all risks and rewards of ownership.

Financial assets and liabilities are offset and the net amount is reported on the consolidated statement of financial position when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

i) Accounts Receivable

Accounts receivable, which are non-derivative financial assets that have fixed or determinable payment terms and are not quoted in an active market, are classified as financial assets at amortized cost and are reported at amortized cost. They are included in current assets.

*ii) Financial Derivative Instrument*s

Risk management contracts and cross-currency swaps are financial derivative instruments and are included in current assets and liabilities, except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets and liabilities. The Company has not designated any of its financial derivative contracts as hedging instruments. The Company's financial derivative instruments are classified as financial assets or liabilities at fair value through profit or loss and are reported at fair value with changes in fair value recorded in net income or loss.

iii) Accounts Payable and Accrued Liabilities and Long-term Debt

These financial instruments are obligations to pay for goods or services that have been acquired in the ordinary course of business from suppliers or repay borrowings from lenders. They are classified as current liabilities if payment is due within one year or less. These financial instruments are classified as financial liabilities at amortized cost and are reported at amortized cost.

iv) Impairment of Financial Assets

The Company recognizes loss allowances for expected credit losses ("**ECLs**") on its financial assets measured at amortized cost. Due to the nature of its financial assets, the Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events 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.

Fair value measurements

All financial and non-financial assets and liabilities for which fair value is measured or disclosed in these financial statements are further categorized using a three-level hierarchy based upon the inputs used to measure fair value:

- Level 1: Values are based on unadjusted quoted market prices in active markets for identical assets or liabilities.
- Level 2: Values are based on inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices).
- Level 3: Values are based on unobservable inputs.

The fair value hierarchy gives the highest priority to Level 1 inputs and the lowest priority to Level 3 inputs. At each reporting date, the Company determines whether transfers have occurred between levels in the hierarchy by reassessing the level of classification for each asset or liability measured or disclosed at fair value.

Fair values in these financial statements have been determined for measurement and/or disclosure purposes based on the following methods. When applicable, further information about the assumptions made in determining fair values is disclosed in the notes specific to that asset or liability.

- The value in use or fair value less costs of disposal is calculated to determine the recoverable amount of non-financial assets that are tested for impairment.
- The fair value of risk management contracts, foreign exchange swaps, or cross-currency swaps are based on listed market prices, if available. If a listed market price is not available, then fair value is estimated by discounting the difference between the contractual price and the current forward price for the residual maturity of the contract using a risk-free interest rate.
- The fair value of long-term debt is based upon observable market data and/or other sources utilizing assumptions that market participants would use to determine fair value.

Revenue

Revenues from the sale of crude oil and natural gas are measured based on the consideration specified in contracts with customers. The Company recognizes revenue when it transfers control of the product to the buyer and collection is reasonably assured. This is generally considered to occur when legal title to the product passes to customers, which is when it is physically transferred to the pipeline or other transportation method agreed upon. Purchases and sales of products that are entered into in contemplation of each other with the same counter party are recorded on a net basis. Royalty income is recognized as it accrues in accordance with the terms of the overriding royalty agreements.

The Company satisfies its performance obligations in contracts with customers upon the delivery of crude oil and natural gas, which is generally at a point in time. Performance obligations for services are satisfied over time as the service is provided. The Company sells its production of crude oil and natural gas pursuant to variable price contracts which generally have a term of one year or less. The transaction price for variable price contracts is based on the commodity index price, adjusted for quality, location and other factors depending on the contract terms. The amount of revenue recognized is based on the agreed transaction price with any variability in transaction price recognized in the same period.

The Company's revenue transactions do not contain significant financing components and payments are typically collected on the 25th day of the month following the prior month's production, with revenue being recorded once the product is delivered to a contractually agreed upon delivery point. The Company does not disclose or quantify information about remaining performance obligations that have an original expected duration of one year or less and it does not have any long-term contracts with unfulfilled performance obligations.

Deferred revenue

For certain oil sales transported by rail, Strathcona receives consideration before the performance obligation is satisfied. The Company reports this as deferred revenue. The Company recognizes revenue when it transfers control of the product to the buyer and collection is reasonably assured.

Blending and transportation and processing expenses

The costs associated with the transportation of oil and natural gas, including the cost of diluent used in blending, are recognized when the product is sold.

Income tax

Income tax expense includes current and deferred tax. Income tax expense is recognized in earnings except to the extent that it relates to a business combination, items recognized directly in equity or other comprehensive income.

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

Deferred tax is recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit or loss. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized for unused tax losses, tax credits and deductible temporary differences, 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.

Net income per share

Basic net income per share is calculated by dividing the net income attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted net income per share is determined by adjusting the net income attributable to common shareholders and the weighted average number of common shares outstanding for the effects of all potential common shares.

Segment reporting

An operating segment is a component of the Company that engages in business activities from which it may earn revenues and incur expenses. Segment results include items directly attributable to a segment as well as those that can be allocated on a reasonable basis. All inter-segment transactions are eliminated on consolidation.

The operating segments of the Company have been derived because: (a) they engage in business activities from which revenues are earned and expenses are incurred; (b) their operating results are regularly reviewed by the Company's chief operating decision makers, identified as the Company's Chief Financial Officer, Chief Commercial Officer, Chief Operating Officer and Executive Chairman to make decisions about resources to be allocated to each segment and assess its performance; and (c) discrete financial information is available. The Company has four business units established to monitor operational performance of groups of assets at a disaggregated level; financial performance and capital allocation decisions are made at the operating segment level. The chief operating decision makers evaluate financial performance and allocate resources to operating segments primarily based on field operating earnings. Field operating earnings is defined as oil and natural gas sales and sale of purchased product less royalties, purchased product, production and operating expenses, blending costs, transportation and processing expenses and depletion, depreciation and amortization.

Changes in accounting policies

Future Accounting Pronouncements

The Company has not early adopted any standard, interpretation or amendment that has been issued but not yet effective.

IFRS 18 Presentation and Disclosure in Financial Statements

In April 2024, the IASB finalised issuance of Presentation and Disclosure in Financial Statements, which will replace IAS 1, "Presentation of Financial Statements". The objective of IFRS 18 is to set out requirements for the presentation and disclosure of information in general purpose financial statements to help ensure they provide relevant information that faithfully represents an entity's assets, liabilities, equity, income and expenses and provide disclosures on management-defined performance measures in the notes to the financial statements. The standard is effective for annual periods beginning on or after January 1, 2027. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

4. ACQUISITIONS

2024

For the year ended December 31, 2024, there were no significant acquisitions.

2023

Acquisition of Pipestone Energy Corp.

On October 3, 2023, Strathcona completed the acquisition of Pipestone, at which time Pipestone and Strathcona were amalgamated and formed Strathcona Resources Ltd. The acquisition was structured through the Arrangement, where existing

Pipestone shareholders received 0.067967 common shares of Strathcona Resources Ltd. for each Pipestone common share (19,010,920 Strathcona Resources Ltd. common shares), and Strathcona shareholders received 0.089278 common shares of Strathcona Resources Ltd. for each Strathcona Class A or Class B common share (195,224,688 Strathcona Resources Ltd. common shares).

The consideration for the acquisition was valued using the acquisition date fair value of Pipestone's equity interest as it was based on a quoted and reliable market price. The value of the consideration was $537.0 million.

The Company opted to apply the optional IFRS 3 concentration test, which resulted in the Pipestone acquisition being accounted as an asset acquisition.

The results of operations of Pipestone are included in these financial statements from the date of closing of the acquisition on October 3, 2023.

Assets Acquired and Liabilities Assumed

The following table summarizes the total consideration paid and net assets acquired:

Consideration	
Fair value of common shares issued	537.0
Capitalized transaction costs	23.4
Total consideration	560.4
Accounts receivable	54.1
Prepaid expenses and deposits	8.9
Risk management asset	1.1
Oil and natural gas properties	772.1
Right of use asset	106.2
Accounts payable and accrued liabilities	(89.3)
Risk management liability	(4.2)
Debt	(179.2)
Lease liability	(106.2)
Decommissioning provision	(3.1)
Net assets acquired	560.4

5. PROPERTY, PLANT AND EQUIPMENT

	Oil and natural gas properties	Exploration and evaluation assets	Corporate Assets	Right of Use Assets	Total
Cost					
Balance, January 1, 2023	9,848.6	117.3	37.6	127.4	10,130.9
Additions	1,017.5	—	10.9	61.8	1,090.2
Pipestone Acquisition (Note 4)	772.1	—	—	106.2	878.3
Change in decommissioning provision (Note 8)	66.2	—	—	—	66.2
Balance, December 31, 2023	11,704.4	117.3	48.5	295.4	12,165.6
Additions	1,287.2	—	9.0	16.8	**1,313.0**
Acquisitions and dispositions	41.0	—	—	—	**41.0**
Change in decommissioning provision (Note 8)	(52.9)	—	—	—	**(52.9)**
Balance, December 31, 2024	**12,979.7**	**117.3**	**57.5**	**312.2**	**13,466.7**
Accumulated DD&A and Impairment					
Balance, January 1, 2023	(1,351.0)	—	(29.2)	(26.5)	(1,406.7)
Depletion, depreciation and amortization	(694.5)	—	(5.7)	(28.6)	(728.8)
Balance, December 31, 2023	(2,045.5)	—	(34.9)	(55.1)	(2,135.5)
Depletion, depreciation and amortization	(820.7)	—	(7.4)	(46.7)	**(874.8)**
Balance, December 31, 2024	**(2,866.2)**	**—**	**(42.3)**	**(101.8)**	**(3,010.3)**
Net book value, December 31, 2023	9,658.9	117.3	13.6	240.3	10,030.1
Net book value, December 31, 2024	**10,113.5**	**117.3**	**15.2**	**210.4**	**10,456.4**

For the year ended December 31, 2024, $52.1 million of direct and incremental overhead charges were capitalized ($38.0 million for the year ended December 31, 2023).

The calculation of depletion for the year ended December 31, 2024 includes $11.5 billion of estimated future development costs required to bring the Company's estimated proved plus probable reserves to production (December 31, 2023 – $13.0 billion). Depletion includes an adjustment related to oil inventory of $1.3 million (December 31, 2023 – $4.1 million).

At December 31, 2024, the Company evaluated its CGUs for indicators of impairment and determined that no indicators were present.

6. DEBT

As at	December 31, 2024	December 31, 2023
Revolving Credit Facility - due Mar 28, 2028[1]	**1,766.9**	2,036.3
Senior Notes - due Aug 1, 2026	**719.2**	662.2
Unamortized debt issuance costs	**(24.5)**	(33.5)
Debt	**2,461.6**	2,665.0

(1) The Company periodically borrows from its Revolving Credit Facility in US dollars ("**USD**" or "**US$**") and concurrently enters into cross-currency interest rate swap ("**CCS**") contracts to take advantage of an interest rate arbitrage that results from the relationship between CAD and USD interest rates and forward foreign exchange curves. Foreign currency risk associated with these borrowings are offset at the time of borrowing using CCS contracts (see Note 14). Debt on the balance sheet includes the CAD equivalent of USD borrowings, translated at the period end exchange rate, which does not include the offsetting impact of CCS contracts. At December 31, 2024, the CCS contracts had an asset value of $28.6 million (December 31, 2023 - $39.6 million liability) and total debt includes an unrealized loss of $28.6 million (December 31, 2023 - unrealized gain of $41.3 million) related to USD borrowings on the Revolving Credit Facility. Unrealized gains or losses on USD borrowings and offsetting unrealized gains or losses on CCS contracts are included in foreign exchange gains or losses on the Consolidated Statements of Income and Comprehensive Income (see Note 11).

Bank Credit Facilities

(a) Covenant-Based Revolving Credit Facility and Term Credit Facility

As at December 31, 2024, the Company had a covenant-based revolving credit facility of $2.5 billion (December 31, 2023 - $2.3 billion) with a syndicate of Canadian, U.S. and international financial institutions (the "**Revolving Credit Facility**"). In January 2025, the Company amended and restated the credit agreement governing the Revolving Credit Facility to, among other things, add a US$175.0 million covenant-based term facility (the "**Term Credit Facility**" and together with the Revolving Credit Facility, the "**Credit Facilities**") to its bank Credit Facilities (such credit agreement as so amended and restated, the "**Credit Agreement**") and to incorporate an accordion feature which permits the Company to increase the Credit Facilities available under the Credit Agreement by up to an additional $250.0 million, subject to the satisfaction of certain conditions.

The Credit Facilities have a maturity date of March 28, 2028, provided that the maturity date will be May 1, 2026 if the Senior Notes (as defined below) remain outstanding and have not been refinanced or legally defeased at such date. There are no mandatory payments on either the Revolving Credit Facility or the Term Credit Facility. Borrowings under the Revolving Credit Facility may be drawn and repaid from time to time by the Company in Canadian or U.S. dollars. The Term Credit Facility was made available by way of a single advance, which was fully funded on January 29, 2025. Borrowings under the Term Credit Facility are available in U.S. dollars only and amounts repaid by the Company may not be re-borrowed. The proceeds of the Term Credit Facility were used to repay borrowings under the Revolving Credit Facility. In addition, the Revolving Credit Facility is not a borrowing base facility and does not require annual or semi-annual reviews.

The Credit Facilities bear interest at the applicable prime lending rate, base rate, Canadian Overnight Repo Rate Average ("**CORRA**") or Secured Overnight Financing Rate ("**SOFR**") plus applicable margins. The applicable margin charged by the lenders is dependent on the Company's Senior Debt to Adjusted EBITDA ratio (as defined below) for the most recently completed quarter. The Credit Facilities are guaranteed by the Company's subsidiaries, and are secured by a security interest in substantially all of the existing and future assets of the Company and its subsidiaries, including by way of a floating charge debenture granted by the Company and each of its subsidiaries.

As at December 31, 2024, the Company had letters of credit outstanding under the Revolving Credit Facility of $1.6 million (December 31, 2023 - $10.6 million).

(b) Availability under bank credit facility

Availability under the Company's Revolving Credit Facility is calculated as follows:

As at	December 31, 2024	December 31, 2023
Credit capacity	**2,500.0**	2,300.0
Credit facility debt at period end exchange rate	**(1,766.9)**	(2,036.3)
Unrealized loss (gain) on US borrowings	**28.6**	(41.3)
Letters of credit outstanding	**(1.6)**	(10.6)
Availability	**760.1**	211.8

(c) Financial Covenants

The Credit Agreement has three financial covenants which are calculated quarterly (as set out below).

(i) Total Debt to Adjusted EBITDA Ratio – All debt excluding the Financing Agreement (see Note 7), capital leases and letters of credit constituting debt ("**Total Debt**"), each as defined in the Credit Agreement shall not exceed 4.0 times trailing 12-month net income before non-cash items, income taxes, interest expense and extraordinary and non-recurring losses, adjusted for material acquisitions or dispositions as if they occurred on the first day of the calculation period ("**Adjusted EBITDA**"). For the purposes of Adjusted EBITDA, lease payments are deducted from the calculation if a lease would have been considered an operating lease before the adoption of IFRS 16. Total Debt may include the value of the Company's undiscounted inactive abandonment and reclamation obligations for a material jurisdiction if the liability management ratio in that jurisdiction falls below the minimum maintenance level required under the Credit Agreement (1.0 in British Columbia and 2.0 in all other material jurisdictions). Liability management ratios are calculated by provincial regulators based on deemed asset and deemed liability values determined by the respective regulator, other than for British Columbia, which is calculated by the Company based on past practice of the BC Oil and Gas Commission.

(ii) Senior Debt to Adjusted EBITDA Ratio – Total Debt excluding permitted junior debt (e.g. Senior Notes), as defined in the Credit Agreement, shall not exceed 3.5 times trailing 12-month Adjusted EBITDA.

(iii) Interest Coverage Ratio – Trailing 12-month Adjusted EBITDA, shall not be less than 3.5 times cash interest expense, as defined in the Credit Agreement.

As at December 31, 2024, the Company was in compliance with such financial covenants, which are summarized in the following table:

As at	December 31, 2024
Total Debt to Adjusted EBITDA Ratio (≤ 4.00)	**1.20**
Senior Debt to Adjusted EBITDA Ratio (≤ 3.50)	**0.85**
Interest Coverage Ratio (≥ 3.50)	**10.95**

Senior Notes

As at December 31, 2024, Strathcona had $719.2 million (December 31, 2023 - $662.2 million) of senior unsecured notes outstanding, in aggregate principal amount of US$500.0 million, due August 1, 2026 (the "**Senior Notes**"). The Senior Notes bear interest at 6.875% per annum, payable semi-annually in arrears on February 1 and August 1 of each year. The Senior Notes are redeemable at Strathcona's option, in whole or in part, at the following redemption prices:

Date	Price
August 1, 2024	**101.719 %**
August 1, 2025 and thereafter	**100.000 %**

The Senior Notes have no financial maintenance covenants.

Demand Letter of Credit Facility

As at December 31, 2024, the Company had a $100.0 million (December 31, 2023 - $100.0 million) demand letter of credit facility with a financial institution (the "**LC Facility**"). The LC Facility is supported by an account performance security guarantee issued by Export Development Canada in favour of the financial institution. The Company and its subsidiaries have indemnified Export Development Canada for the amount of any payment made by Export Development Canada to the financial institution pursuant to such account performance security guarantee; however, the obligations under such indemnity are unsecured. The letters of credit outstanding under the LC Facility do not impact the Company's borrowing capacity under the Revolving Credit Facility. As at December 31, 2024, the Company had letters of credit in the amount of $70.3 million (December 31, 2023 - $69.0 million) outstanding under the LC Facility.

Interest Expense

For the Year Ended December 31,	2024	2023
Credit facilities interest(1)	**146.1**	178.4
Senior Notes interest	**47.1**	46.4
Realized gain on interest rate swaps	**(23.0)**	(18.6)
Interest expense	**170.2**	206.2

(1) Interest on bank credit facilities in 2023 includes interest on the Revolving Credit Facility and, prior to its repayment on December 28, 2023, the then term credit facility.

7. LEASE AND OTHER OBLIGATIONS

As at	December 31, 2024	December 31, 2023
Lease obligations, beginning of year	**258.8**	119.5
Leases acquired through acquisitions	**—**	106.2
Additions	**16.8**	61.8
Accretion (Note 10)	**24.1**	14.5
Settlements	**(69.5)**	(43.6)
Foreign exchange	**4.4**	0.4
Lease obligations, end of year	**234.6**	258.8
Other obligations, beginning of year	**147.4**	137.0
Additions	**112.4**	—
Accretion (Note 10)	**15.4**	19.1
Settlements	**(167.2)**	(8.7)
Loss on settlement	**4.4**	—
Other obligations, end of year	**112.4**	147.4
Lease and other obligations, end of year	**347.0**	406.2
Lease and other obligations current portion	**64.5**	43.8
Lease and other obligations long-term portion	**282.5**	362.4

Other obligations, beginning of the period included an asset-backed financing agreement on certain processing facility interests with a maturity date of January 1, 2031. This asset-backed financing arrangement gave the Company the option to repurchase the processing facilities interest at any time at specified prices. On July 15, 2024, Strathcona exercised this repurchase option for $157.6 million.

On August 9, 2024 Strathcona entered into a new asset-backed financing agreement backed by its interest in certain processing facility interests (the "**Financing Agreement**") for $112.4 million, which consideration was provided by way of the lender's concurrent assumption of premiums on bought calls from Strathcona (see Note 14).

The Financing Agreement has a maturity date of July 31, 2029 and bears interest at a fixed rate. Principal and interest payments are due monthly, with principal payments commencing February 1, 2025. The Company may also repurchase the processing facilities interest (the "**Repurchase Option**") at any time at the specified prices set out in the Financing Agreement.

The Repurchase Option is a combination of the remaining principal balance and a varying option premium that is dependent on the time of exercise.

8. DECOMMISSIONING PROVISION

As at	December 31, 2024	December 31, 2023
Balance, beginning of year	**351.3**	291.5
Additions	**8.5**	1.6
Liabilities acquired through acquisitions	**—**	3.1
Liabilities disposed	**(0.5)**	—
Settlements – government grant[1]	**0.2**	(0.3)
Settlements – other	**(35.7)**	(37.9)
Changes in estimates	**(61.4)**	64.6
Accretion (Note 10)	**28.3**	28.7
Balance, end of year	**290.7**	351.3
Current portion	**40.9**	36.6
Long-term portion	**249.8**	314.7

(1) Relates to amounts granted to the Company through the Site Rehabilitation Program (Alberta), Dormant Sites Reclamation Program (British Columbia) and the Accelerated Site / Closure Program (Saskatchewan) to pay service companies to complete abandonment and reclamation work.

As at December 31, 2024, the uninflated and undiscounted estimated cash flows required to settle the obligation were $1,040.6 million (December 31, 2023 – $1,012.9 million), which have been inflated at a rate of 2.00% (December 31, 2023 – 2.00%) and discounted using a credit adjusted rate of 10.00% (December 31, 2023 – 8.00%). The expected timing of payment of the cash flows required for settling the obligations are substantially expected to be incurred between 2025 and 2083.

9. OIL AND NATURAL GAS SALES

For the Year Ended December 31,	2024	2023
Bitumen blend	**2,576.0**	2,280.8
Heavy oil, blended and raw	**1,795.7**	1,809.1
Light oil and condensate	**704.7**	431.0
Other natural gas liquids	**106.1**	79.4
Natural gas	**153.9**	148.0
Oil and natural gas sales	**5,336.4**	4,748.3

10. FINANCE COSTS

For the Year Ended December 31,	2024	2023
Accretion of lease obligations (Note 7)	**24.1**	14.5
Accretion of other obligations (Note 7)	**15.4**	19.1
Accretion of decommissioning provision (Note 8)	**28.3**	28.7
Amortization of debt issuance costs	**20.5**	13.0
Finance costs	**88.3**	75.3

11. FOREIGN EXCHANGE LOSS (GAIN)

For the Year Ended December 31,	2024	2023
Realized loss (gain) – foreign exchange	**0.5**	(1.4)
Unrealized loss (gain) – Senior Notes	**57.0**	(15.6)
Unrealized loss (gain) – Credit facilities[1]	**69.8**	(47.2)
Unrealized (gain) loss – cross-currency swaps[1]	**(68.2)**	43.9
Unrealized loss (gain) – other	**9.1**	(1.8)
Foreign exchange loss (gain)	**68.2**	(22.1)

(1) Strathcona enters into CCS contracts, which offset foreign currency risk on USD denominated debt drawn under the bank credit facilities. At maturity, the realized gains and losses relating to USD borrowings will be offset by the realized gains and losses on CCS contracts. See Note 6.

12. SHARE CAPITAL

(a) Share Capital

	Total Common Shares	
	Shares	$
Balance as at December 31, 2024 and December 31, 2023	**214.2**	**3,590.5**

(b) Net Income (Loss) per Share

Basic and diluted per share amounts are calculated as net income divided by the weighted average number of common shares outstanding. At December 31, 2024 and 2023, the Company had no dilutive instruments outstanding.

For the Year Ended December 31,	2024	2023
Weighted average common shares (millions) – basic and diluted	**214.2**	199.9

(c) Dividends

During the year ended December 31, 2024, Strathcona declared and paid total dividends of $107.1 million, or $0.50 per common share ($nil - in the year ended December 31, 2023).

On March 4, 2025, the Board declared a quarterly dividend of $0.26 per common share to be paid on March 31, 2025 to all shareholders of record on March 21, 2025.

13. INCOME TAXES

Estimated future income tax deductions

The Company has approximately $5,595.4 million of estimated future income tax deductions, in various taxpool categories, available at December 31, 2024 (December 31, 2023 - $6,081.1 million).

Total income tax expense

	2024	2023
Current	—	(46.9)
Deferred		
Origination and reversal of temporary differences	**215.2**	255.2
Change in expected statutory tax rates	**(3.6)**	(0.8)
Adjustments for prior years	**16.3**	41.8
Change in unrecognized tax losses	**21.4**	—
	249.3	296.2
Total income tax expense	**249.3**	249.3

During the year ended December 31, 2023, a current tax recovery of $46.9 million was recorded upon filing of the final tax return of Serafina Energy Ltd., which resulted from an income tax election to apply fair value treatment to financial derivative contracts. The current tax recovery was offset by a corresponding deferred tax expense due to the liability recorded by Strathcona to reflect the income inclusion related to the election filed.

Reconciliation of effective tax rate

	2024	2023
Net income before income tax	**853.0**	836.5
Expected tax rate	**24.1 %**	24.3 %
Expected income tax expense	**205.9**	203.6
Non-deductible expenses	**0.2**	0.3
Change in unrecognized tax losses	**21.4**	—
Change in expected statutory tax rates	**(3.6)**	(0.8)
Adjustments for prior years	**16.3**	41.8
Other	**9.1**	4.4
Total income tax expense	**249.3**	249.3

Recognized deferred income tax asset and liabilities

The movement in deferred income tax assets and liabilities is as follows:

	January 1, 2024	Recognized in earnings	December 31, 2024
Deferred income tax assets			
Financial derivative contracts	25.3	(15.5)	**9.8**
Decommissioning provision	85.5	(15.3)	**70.2**
Lease and other obligations	62.8	(6.2)	**56.6**
Non-capital losses	530.7	(112.5)	**418.2**
Financing costs	3.7	0.1	**3.8**
Other	52.3	1.9	**54.2**
	760.3	(147.5)	**612.8**
Deferred income tax liabilities			
Deferred partnership income	(7.2)	(4.2)	**(11.4)**
Property, plant and equipment	(1,494.5)	(97.6)	**(1,592.1)**
	(1,501.7)	(101.8)	**(1,603.5)**
Deferred tax liability	**(741.4)**	**(249.3)**	**(990.7)**

	January 1, 2023	Recognized in earnings	December 31, 2023
Deferred income tax assets			
Financial derivative contracts	51.8	(26.5)	**25.3**
Decommissioning provision	71.1	14.4	**85.5**
Lease and other obligations	29.4	33.4	**62.8**
Non-capital losses	716.9	(186.2)	**530.7**
Financing costs	4.5	(0.8)	**3.7**
Other	59.6	(7.3)	**52.3**
	933.3	(173.0)	**760.3**
Deferred income tax liabilities			
Deferred partnership income	(61.3)	54.1	**(7.2)**
Property, plant and equipment	(1,317.2)	(177.3)	**(1,494.5)**
	(1,378.5)	(123.2)	**(1,501.7)**
Deferred tax liability	**(445.2)**	**(296.2)**	**(741.4)**

Non-capital losses

Expiry Year	2031	2032	2033	2034	2035	Thereafter	Total
Non-capital loss balances	42.2	479.6	327.8	273.9	37.5	546.6	1,707.6

Unrecognized deferred income tax assets

A temporary difference has not been recognized in respect of the following items:

	2024	2023
Property, plant and equipment	**155.7**	80.2
Capital losses	**67.8**	67.7
Scientific research and experimental development income tax credits	**4.5**	—
	228.0	147.9

14. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

At December 31, 2024, the Company's financial instruments include accounts receivable, risk management contracts, CCS contracts, the Sable remediation fund, accounts payable and accrued liabilities, cross-currency swaps, other obligations and debt.

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of the financial instruments, other than the Company's risk management contracts and debt approximate their carrying amounts due to the short-term maturity of these instruments.

The Company's risk management contracts and CCS contracts were classified as Level 1 in the fair value hierarchy. For purposes of estimating the fair value of these instruments, the Company used quoted market prices in active markets for identical assets or liabilities.

The Company's Senior Notes were classified as Level 1 in the fair value hierarchy. At December 31, 2024, the fair value of the Company's Senior Notes was $720.0 million. The fair value of all other debt approximates its carrying amount given the indexed rates of interest.

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production and financing activities. These risks include credit risk, liquidity risk and market risk. There have been no significant changes in the Company's risk management policies or exposures during the year ended December 31, 2024.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligations. This will arise principally from outstanding receivables related to oil and natural gas customers, counterparties related to financial derivative contracts and joint interest partners.

On entering into any business contract, the extent to which the arrangement exposes the Company to credit risk is considered. The Company's policy to mitigate credit risk associated with these balances is to establish relationships with reputable counterparties, review the financial capacity of its counterparties, may request prepayment and, in certain circumstances, the Company may seek enhanced credit protection from a counterparty or purchase accounts receivable insurance. Receivables from oil and natural gas sales are generally collected on or about the 25^{th} day of the month following production. Joint operations receivables are typically collected within one to three months of the invoice being issued.

The Company's maximum exposure to credit risk at December 31, 2024 is in respect of accounts receivable, risk management assets and CCS, net of expected credit losses provision. As at December 31, 2024, $1.2 million of accounts receivable were past due, all of which were considered collectable (December 31, 2023 – $2.1 million).

The following table provides a summary of the Company's maximum exposure to credit risk:

As at	December 31, 2024	December 31, 2023
Oil and natural gas sales	**325.5**	298.3
Joint interest partners	**5.1**	7.1
Other	**20.0**	30.8
	350.6	336.2
Allowance for credit losses	**(2.4)**	(1.6)
Accounts receivable	**348.2**	334.6
Cross-currency swap asset	**28.6**	—
Risk management asset	**47.0**	41.3
Total credit exposure	**423.8**	375.9

The oil and gas industry has a pre-arranged monthly clearing day for payment of revenues from all buyers of oil and natural gas; this occurs on or about the 25th day following the month of sale. As a result, the Company's oil and natural gas sales receivables are current. All other accounts receivable are generally contractually due within 30 days.

The Company had no external customer exceeding 10% of total oil and natural gas sales for the year ended December 31, 2024 (December 31, 2023 – one external customer for 16% or $738.0 million). Included in accounts receivable at December 31, 2024 was $325.5 million of accrued sales revenue for December 2024 production (December 31, 2023 - $298.3 million for December 2023 production). At December 31, 2024, one external customer accounted for approximately 10% or $31.3 million of the total accounts receivable balance (December 31, 2023 – two external customers for 31% or $104.6 million).

Credit risk related to joint interest receivables is mitigated by obtaining partner approval of significant capital expenditures prior to expenditure and in certain circumstances may require cash deposits in advance of incurring financial obligations on behalf of joint interest partners. The Company may have the ability to withhold production from joint interest partners in the event of non-payment or may be able to register security on the assets of joint interest partners.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company regularly prepares and updates budgets and forecasts in order to monitor its liquidity and ability to meet its financial obligations and commitments, including the ability to comply with financial covenants. As of the date of these financial statements, management's forecasts for Strathcona indicate that financial covenants for the next twelve months will be met under the Credit Facilities and that the Company has sufficient resources to manage the working capital deficit.

At December 31, 2024, the Company had availability under the Revolving Credit Facility of $760.1 million after considering letters of credit outstanding. At December 31, 2023, availability under the Revolving Credit Facility was $211.8 million, see Note 6.

Future liquidity depends on the ability of Strathcona to access debt markets, availability under credit facilities, availability of additional equity, cash flow from operations and the ability to comply with financial covenants. Various industry risk factors, including uncertainty around improvements in global commodity prices and pipeline and transportation capacity constraints in Western Canada, may adversely affect Strathcona's future liquidity.

At December 31, 2024, the Company had a working capital deficit of $545.6 million (December 31, 2023 - $415.3 million). The deficit primarily results from accounts payable and accrued liabilities exceeding accounts receivable.

The following tables detail the cash flows and contractual maturities of the Company's financial liabilities:

As at December 31, 2024	Total	<1 year	1-3 years	4-5 years	> 5 years
Revolving Credit Facility[1] (Note 6)	**1,738.3**	—	1,738.3	—	—
Senior Notes[2] (Note 6)	**818.0**	49.4	768.6	—	—
Accounts payable and accrued liabilities	**918.7**	918.7	—	—	—
Risk management contract liability	**87.7**	44.6	43.1	—	—
Lease and other obligations[3] (Note 7)	**473.7**	91.4	151.6	143.8	86.9
Total	**4,036.4**	1,104.1	2,701.6	143.8	86.9

(1) Contractual amount reflects contracted settlement price on cross-currency interest rate swap ("CCS") contracts and excludes future interest payments on borrowings.

(2) Amounts represent repayment of the Senior Notes ($719.2 million) and associated interest payments ($98.8 million) based on the foreign exchange rate in effect on December 31, 2024.

(3) Amounts relate to undiscounted payments for lease and other obligations. The estimation of future cash payments related to other obligations reflects minimum required payments and may change based on the principal and interest payment options taken. See Note 7.

Market risk

Market risk is the risk that the future fair value or cash flows of a financial instrument will fluctuate due to changes in market prices. Market risk is composed of commodity price risk, foreign exchange risk and interest rate risk.

As at December 31, 2024, the following table summarizes the fair values of the Company's risk management contracts (excluding cross-currency interest rate swaps):

As at	December 31, 2024			
	Commodity	Foreign Exchange	Interest Rate	Total
Risk management asset – current	**47.0**	**—**	**—**	**47.0**
Risk management liability – current	**—**	**(43.0)**	**(1.6)**	**(44.6)**
Risk management liability – long-term	**—**	**(14.1)**	**(29.0)**	**(43.1)**
Total (liability) asset	**47.0**	**(57.1)**	**(30.6)**	**(40.7)**

As at	December 31, 2023			
	Commodity	Foreign Exchange	Interest Rate	Total
Risk management asset – current	23.5	—	17.8	41.3
Risk management liability – current	(101.9)	(23.5)	—	(125.4)
Risk management liability – long-term	—	(4.6)	(15.0)	(19.6)
Total (liability) asset	(78.4)	(28.1)	2.8	(103.7)

The Company's (loss) gain risk management contracts was as follows:

For the Year Ended December 31,	2024	2023
Loss on risk management contracts - realized[1]	**(107.0)**	(42.4)
Gain on risk management contracts - unrealized	**63.0**	112.0
Total (loss) gain on risk management contracts	**(44.0)**	69.6

(1) During the year ended December 31, 2024, the Company settled premiums associated with expired bought calls for non-cash consideration of $112.4 million (see Note 7 and 17).

Commodity price risk

The Company's operational results and financial condition are largely dependent on the commodity price received for oil and natural gas production. Commodity prices may be impacted by global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, global pandemic or natural disasters and respective responses from various levels of government, economic and geopolitical factors. Changes in commodity prices could have a significant positive or negative impact on Strathcona's net income.

The following table summarizes the Company's risk management contracts as at December 31, 2024:

Term	Contract(1)	Index	Currency	Volume	Units	Price
Jan 1, 2025 - Dec 31, 2025	Swap	WCS	USD	45,000	bbl/d	($12.94)
Dec 1, 2024 - Mar 31, 2025	Collar	AECO	CAD	30,000	GJ/d	$2.50/$3.51

(1) For swap contracts, Strathcona receives the fixed price and pays the index. For collars, Strathcona receives the floor price if the index is below the floor and the cap price if the index is above the cap.

The fair value of the Company's risk management contracts as at December 31, 2024 are sensitive to fluctuations in commodity prices. With all other variables held constant, a 10% increase in commodity prices could increase the unrealized gain on risk management contracts by $35.5 million, impacting income before income taxes. A 10% decrease in commodity prices could reduce the unrealized gain on risk management contracts by $32.9 million, impacting income before income taxes.

Foreign exchange risk

The Company is exposed to fluctuations of the CAD to USD exchange rate given commodity pricing is directly influenced by USD denominated benchmark pricing. In addition, the Company borrows from Credit Facilities in USD and the Senior Notes are denominated in USD.

The following table summarizes the Company's foreign exchange contracts on revenues as at December 31, 2024:

Term	Contract	USD per Month	CAD/USD Floor	CAD/USD Ceiling
Mar 1, 2024 - Feb 27, 2026	Collar	60.0 million	1.2500	1.3800

The following table summarizes the Company's foreign exchange contract on the Senior Notes as at December 31, 2024:

Expiry	Contract	USD	CAD/USD Strike
Jul 31, 2026	Sold Put Option	500.0 million	1.3475

Foreign exchange risk on USD denominated borrowings on the Credit Facilities is offset by entering into CCS contracts at the time of a USD borrowing. As part of the CCS, the CAD/USD foreign exchange rate at the beginning and end of the SOFR borrowing term is fixed so the Company does not have any foreign exchange risk on its USD borrowings. As at December 31, 2024, the Company had CCS contracts outstanding totaling:

Notional (US$)	Maturity Date	Contract Price
1,235.0 million	January 17, 2025	CAD/USD 1.4153

The carrying amounts of the Company's USD denominated monetary assets and liabilities exposed to fluctuations in the CAD/USD foreign currency exchange rate are as follows:

As at	December 31, 2024	December 31, 2023
(US$)		
Assets	**110.7**	58.7
Liabilities	**(622.7)**	(738.4)
Net liabilities	**(512.0)**	(679.7)

With all other variables held constant, a $0.01 change in the CAD/USD foreign exchange rate at December 31, 2024 would result in a change in USD denominated monetary assets and liabilities and change income before income taxes by $5.1 million (December 31, 2023 – $6.8 million).

Interest rate risk

The Company is exposed to movements in floating interest rates on the Revolving Credit Facility and other liabilities. At December 31, 2024, the following risk management contracts were in place to fix interest rates:

Notional (C$)	Term(1)	Contract	Index	Contract Price
1,500.0 million	Oct 1, 2024 - Apr 30, 2030	Swap	CORRA	2.9453%

(1) The swap contracts have a term to April 30, 2030. The counterparties have an option to terminate the swap effective May 1, 2028, which is exercisable on April 28, 2028.

At December 31, 2024, an increase or decrease to interest rates of 50 basis points would result in a $1.2 million impact on annualized interest expense (December 31, 2023 - $3.6 million), impacting income before income taxes. The Company is not exposed to interest rate risk on the Senior Notes and other obligations as they bear a fixed interest rate.

Capital management

The Company's policy is to maintain a strong capital base for the objectives of maintaining financial flexibility, creditor and market confidence and to sustain the future development of the business. The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying petroleum and natural gas assets. The Company considers its capital structure to include equity, long-term debt and working capital.

15. COMMITMENTS AND CONTINGENCIES

As at December 31, 2024, the Company is committed to the following non-cancellable payments:

	Total	< 1 year	1-3 years	4-5 years	> 5 years
Transportation and processing commitments	**2,052.7**	284.4	507.2	427.2	833.9
Capital commitments	**139.0**	136.0	3.0	—	—
Other	**27.2**	13.8	10.9	2.5	—
Total	**2,218.9**	434.2	521.1	429.7	833.9

16. RELATED PARTY TRANSACTIONS

For the year ended December 31, 2024, there were no related party transactions other than key management compensation.

Key management personnel of the Company include its officers and directors. Amounts recorded by the Company relating to compensation of directors and officers were as follows:

For the Year Ended December 31,	2024	2023
Key management compensation	**21.8**	13.4

17. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

For the Year Ended December 31,	2024	2023
Source (use) of cash:		
Accounts receivable	**(13.6)**	18.6
Inventory	**(3.2)**	17.2
Prepaid expenses and deposits	**(1.9)**	(9.2)
Accounts payable and accrued liabilities	**129.2**	41.6
Deferred revenue	**19.9**	(12.5)
	130.4	55.7
Related to operating activities	**92.1**	4.3
Related to financing activities	**—**	0.6
Related to investing activities	**38.3**	50.8

Items not involving cash

For the Year Ended December 31,	2024	2023
Depletion, depreciation and amortization (Note 5)	**873.5**	732.9
Unrealized gain on risk management contracts (Note 14)	**(63.0)**	(112.0)
Unrealized loss (gain) on foreign exchange (Note 11)	**67.7**	(20.7)
Unrealized gain on Sable remediation fund	**(0.1)**	(0.2)
Finance costs (Note 10)	**88.3**	75.3
Settlements – government grant (Note 8)	**0.2**	(0.3)
Loss on settlement of other obligations (Note 7)	**4.4**	—
Realized loss on deferred premium settlement (Note 14)	**112.4**	—
Deferred tax expense (Note 13)	**249.3**	296.2
	1,332.7	971.2

18. SEGMENT INFORMATION

The Company has identified three operating segments through examination of the Company's performance which is based on the similarity of services and goods provided and economic characteristics exhibited by the operating segments. The three operating segments are:

- Cold Lake, which includes the development and production of bitumen in the Cold Lake region of Northern Alberta;

- Lloydminster, which includes the development and production of heavy oil through enhanced oil recovery and thermal steam-assisted gravity drainage ("**SAGD**") methods in Southeast Alberta and Southwest Saskatchewan; and

- Montney, which includes the development and production of liquids rich natural gas produced from the Montney region in Northwest Alberta and Northeast British Columbia.

The Company reports activities not directly attributable to an operating segment under Corporate.

The following tables present the financial performance by reportable segment and include a measure of segment profit or loss regularly reviewed by management for the noted periods ended December 31, 2024 and 2023. Certain comparative information related to sale of purchased product and purchased product has been allocated by segment to conform with current period presentation. Field operating earnings is the metric used to evaluate segment profit or loss which includes depletion, depreciation and amortization. Field operating income, which excludes depletion, depreciation and amortization, was used to evaluate segment profit or loss in the comparative period.

For the Year Ended December 31,	Cold Lake 2024	Cold Lake 2023	Lloydminster 2024	Lloydminster 2023	Montney 2024	Montney 2023	Corporate 2024	Corporate 2023	Consolidated 2024	Consolidated 2023
Segment revenues										
Oil and natural gas sales	**2,576.0**	2,279.2	**1,797.1**	1,812.5	**963.0**	655.5	**0.3**	1.1	**5,336.4**	4,748.3
Sale of purchased product	**18.3**	20.1	**26.0**	12.2	**—**	—	**30.7**	14.0	**75.0**	46.3
Royalties	**(385.3)**	(323.3)	**(181.7)**	(175.1)	**(95.7)**	(58.5)	**—**	—	**(662.7)**	(556.9)
Oil and natural gas revenues	**2,209.0**	1,976.0	**1,641.4**	1,649.6	**867.3**	597.0	**31.0**	15.1	**4,748.7**	4,237.7
Segment expenses										
Purchased product	**18.2**	19.5	**25.8**	11.9	**—**	—	**31.0**	15.1	**75.0**	46.5
Blending costs	**929.9**	888.1	**151.6**	170.2	**—**	—	**—**	—	**1,081.5**	1,058.3
Production and operating	**323.9**	372.3	**316.5**	336.8	**171.3**	87.2	**—**	—	**811.7**	796.3
Transportation and processing	**87.7**	80.4	**276.2**	293.7	**213.1**	108.8	**—**	—	**577.0**	482.9
Depletion, depreciation and amortization	**167.1**	148.9	**411.1**	423.2	**278.5**	145.9	**16.8**	14.9	**873.5**	732.9
	1,526.8	1,509.2	**1,181.2**	1,235.8	**662.9**	341.9	**47.8**	30.0	**3,418.7**	3,116.9
Field operating earnings	**682.2**	466.8	**460.2**	413.8	**204.4**	255.1	**(16.8)**	(14.9)	**1,330.0**	1,120.8
Loss on risk management contracts							**44.0**	(69.6)	**44.0**	(69.6)
Other income							**(0.1)**	(1.0)	**(0.1)**	(1.0)
General and administrative							**101.1**	91.9	**101.1**	91.9
Interest							**170.2**	206.2	**170.2**	206.2
Transaction related costs							**1.0**	3.8	**1.0**	3.8
Finance costs							**88.3**	75.3	**88.3**	75.3
Foreign exchange loss (gain)							**68.2**	(22.1)	**68.2**	(22.1)
Unrealized loss on Sable remediation fund							**(0.1)**	(0.2)	**(0.1)**	(0.2)
Loss on settlement of other obligations							**4.4**	—	**4.4**	—
Income before income taxes									**853.0**	836.5
Current tax recovery									**—**	(46.9)
Deferred tax expense									**249.3**	296.2
Income and comprehensive income									**603.7**	587.2

For the Year Ended December 31,	Cold Lake 2024	Cold Lake 2023	Lloydminster 2024	Lloydminster 2023	Montney 2024	Montney 2023	Corporate 2024	Corporate 2023	Consolidated 2024	Consolidated 2023
Capital expenditures	**371.7**	306.0	**445.2**	360.5	**470.3**	351.0	**9.0**	10.9	**1,296.2**	1,028.4
Decommissioning costs[1]	**0.3**	1.8	**14.4**	20.7	**20.8**	15.7	**—**	—	**35.5**	38.2

(1) Decommissioning costs include amounts granted to the Company through the Site Rehabilitation Program (Alberta), Dormant Sites Reclamation Program (British Columbia) and the Accelerated Site Closure Program (Saskatchewan) to pay service companies to complete abandonment and reclamation work.

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